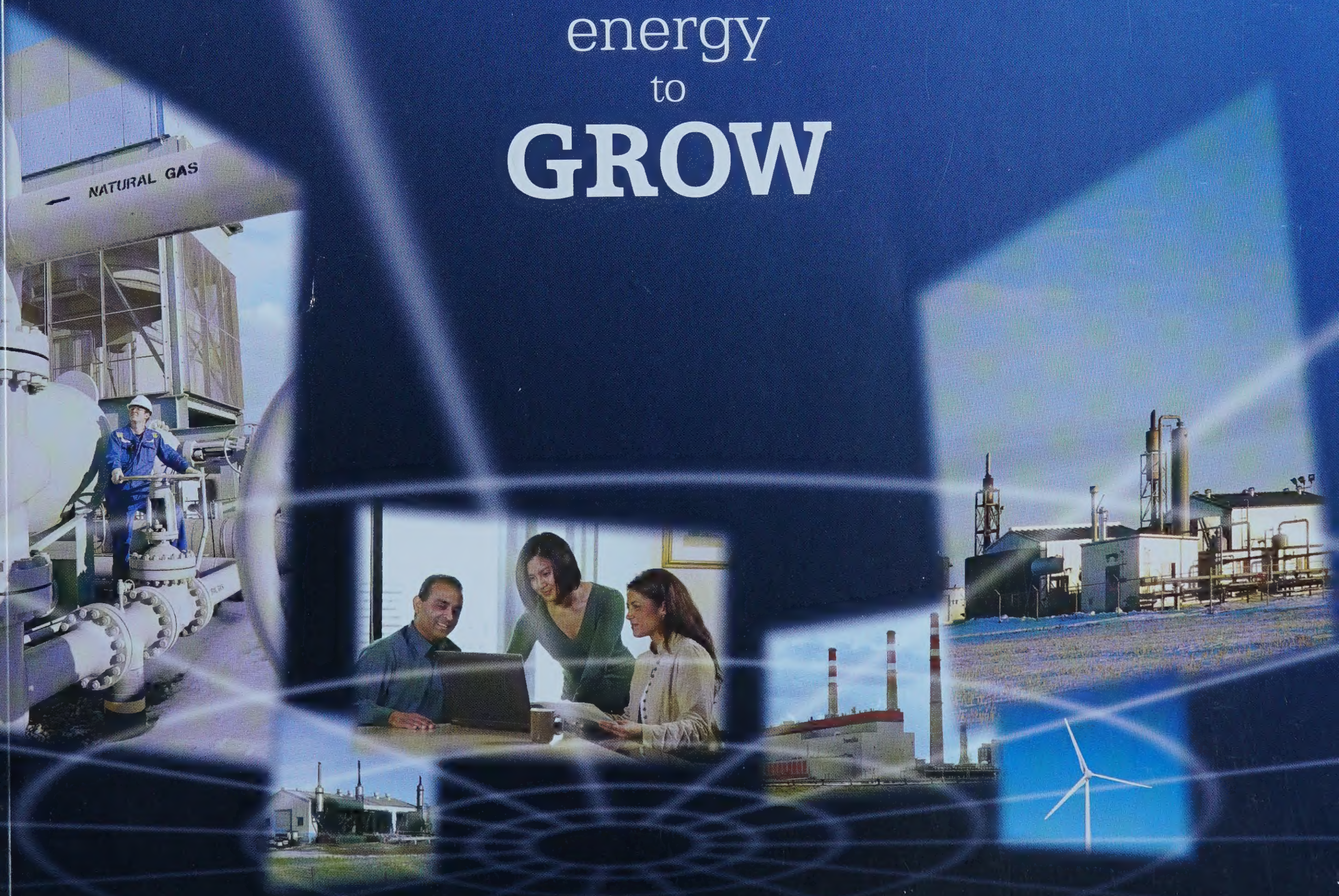
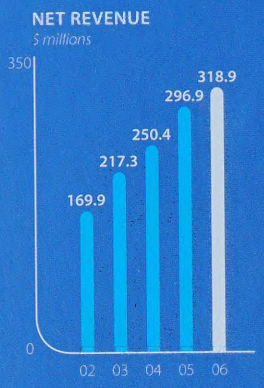
ALTAGAS INCOME TRUST

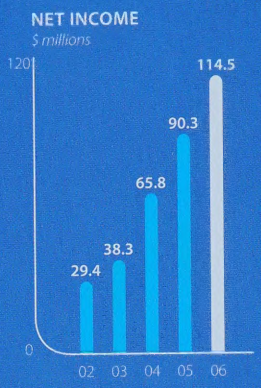
2006 ANNUAL REPORT

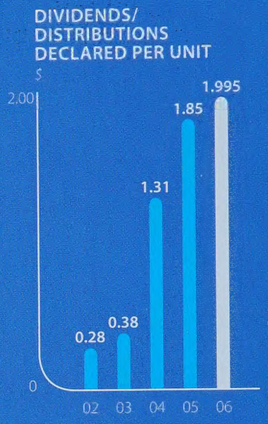
energy to GROW



FINANCIAL **HIGHLIGHTS**







($ millions except as indicated)	**2006**	2005	2004	2003	2002
Revenue	**1,362.6**	1,502.3	864.6	710.6	492.7
Net revenue [1]	**318.9**	296.9	250.4	217.3	169.9
EBITDA [1]	**173.1**	155.5	133.4	121.9	94.8
Net income	**114.5**	90.3	65.8	38.3	29.4
Total assets	**1,109.6**	1,068.3	1,108.6	919.3	904.9
Total debt	**265.5**	269.0	359.5	396.9	419.5
Debt as a percent of total capitalization (%)	**33.4**	36.0	42.6	52.2	55.3
Funds from operations [1]	**161.7**	129.0	108.6	90.2	70.8
Dividends/distributions declared [2]	**110.8**	100.0	66.7	17.3	11.9
$ PER BASIC UNIT					
Net income per unit	**2.06**	1.67	1.33	0.84	0.70
Funds from operations per unit [1]	**2.92**	2.39	2.20	1.98	1.67
Dividends/distributions declared per unit [2]	**1.995**	1.85	1.31	0.38	0.28

(1) Non-GAAP financial measures. See discussion beginning on page 21 in the Management's Discussion and Analysis.

(2) In 2005 an additional distribution valued at $29.3 million ($0.54 per unit) in the form of AltaGas Utility Group Inc. shares was made.

CONTENTS

DEFINITIONS

Bbls/d	barrels per day
Bcf	billion cubic feet
bps	basis points
GJ	gigajoule
GWh	gigawatt-hour
Mcf	thousand cubic feet
Mmcf/d	million cubic feet per day
MW	megawatt
MWh	megawatt-hour

We are integrated

Our four business segments interact to form a single enterprise that is more than the sum of its parts.

We focus on the bottom line

to ensure that our earnings and return on equity provide strong returns to our unitholders.

We invest in our employees

and our communities because helping them grow is the best way to secure our future.

energy to GROW

We have financial flexibility

due to our strong balance sheet and access to capital markets.

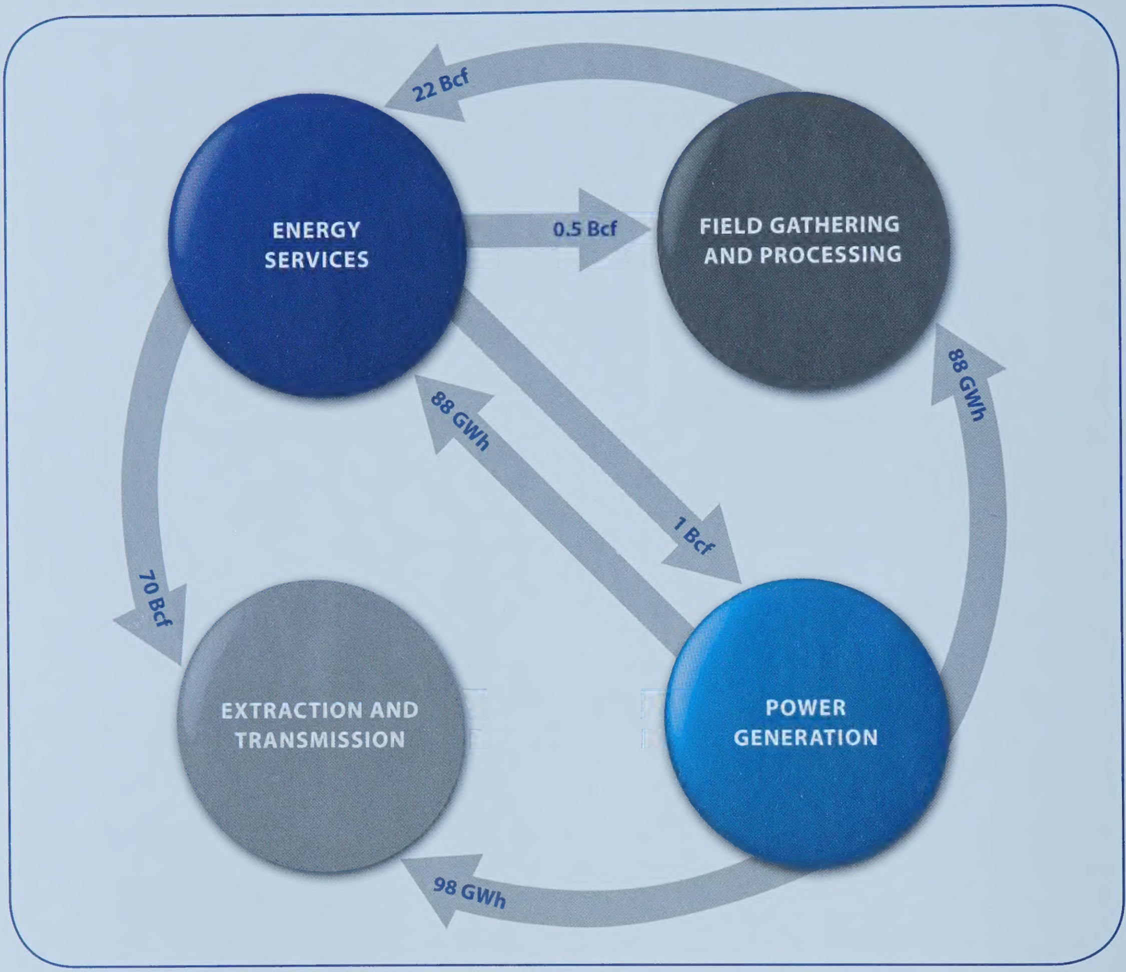
We stay ahead

of the curve, moving our skid-mounted processing facilities to where producers are focusing natural gas exploration and production.

We search the horizon

for new sources of power, with a focus on renewables.

energy to **CREATE VALUE THROUGH INTEGRATION**



AltaGas operates physical assets and provides essential services to customers who produce and consume natural gas and power. The links among our assets, people and processes increase operating efficiencies and utilization across all segments, improve the value proposition to our customers and enhance unitholder value.

Over time we have organized AltaGas into business segments for important operating, reporting and management accountability reasons. The segments' diversity in terms of their revenue source, contractual terms, exposure to industry cycles and geographic location enhances AltaGas' earnings potential. But AltaGas is one business.

The Field Gathering and Processing (FG&P), Extraction and Transmission (E&T) and Power Generation segments are driven by physical assets while the fourth, Energy Services, is primarily intellectual assets and is more about people, processes and market knowledge. Together, the segments create a stronger business better-positioned to grow organically and through acquisitions.

SEGMENT INTEGRATION

The segments either contribute products and services to each other or they are physically connected. It is the

interrelationships of physical assets, services and market knowledge that provide value and opportunities for AltaGas and its customers. Internal business flow amounts to more than $350 million per year. By commodity, almost 275 gigawatt-hours of electricity and 94 billion cubic feet of natural gas per year. This includes:

- Energy Services contracts for approximately 40 Bcf of capacity and exchanges on our transmission pipelines, increasing utilization and margin;
- Energy Services ships 25 Bcf of gas supplies from its customers through our Empress extraction plants, increasing throughput and production at those plants, and purchases 5 Bcf of shrinkage gas on behalf of the extraction plants;
- Power Generation supplies AltaGas' internal electrical demand requirements of 98 GWh for E&T and 88 GWh for FG&P; it also supplies Energy Services' energy management customers with approximately 88 Gwh of power and benefits from having a portion of this in its hedged long-term sales portfolio;
- Energy Services supplies roughly 1 Bcf of natural gas and gas transportation services to Power Generation for its gas-fired peaking plants, which are in turn dispatched by E&T personnel;
- Energy Services markets approximately 22 Bcf on behalf of FG&P producers, providing value to producers, adding margins and reducing credit exposure for AltaGas;
- FG&P processes 0.5 Bcf of natural gas produced by the oil and gas assets in Energy Services; and
- Within Energy Services, the gas services business buys and resells gas to some of its energy management services customers, earning a fixed margin and providing a competitive supply option to customers.

COLD LAKE INTEGRATION

AltaGas' operations in the Cold Lake area are an excellent example of the integration of AltaGas' energy businesses. Transmission, FG&P and Energy Services all operate within this area. The FG&P component of the Cold Lake operating area includes over 646 kilometres of gathering pipelines and 27 facilities, including gas plants and compressor stations that gather and process sweet natural gas. After the natural gas is processed it enters AltaGas' Cold Lake natural gas transmission system, which is approximately 250 kilometres in length and has current operating capacity of 80 Mmcf/d. Energy Services markets or exchanges all volumes that flow through the Cold Lake transmission system. As we move natural gas through the Cold Lake system each of these business segments provides incremental revenue for AltaGas. Ownership of the assets gives us the opportunity to provide customers with cost-effective solutions to move their gas to market.

In November 2006 AltaGas announced an 18 Mmcf/d expansion of the Cold Lake transmission system to supply natural gas to Shell Canada subsidiary BlackRock Ventures Inc.'s (BlackRock) Orion steam-assisted gravity drainage (SAGD) plant beginning in May 2007. Although the capital investment in the project is modest, the project demonstrates our integration strategy in action.

Transmission will construct 4 km of 8-inch diameter pipe and install compression. At the same time the Cold Lake gas transmission system will be revamped by upgrading and/or relocating compressors. This project will make better use of existing compression and dehydration equipment, will result in significant value across AltaGas' Cold Lake businesses and to customers, in addition to supporting the expansion. Gas flow on a portion of the system will be reversed to assist the Energy Services segment in providing BlackRock with natural gas supply of up to 17,000 GJ per day.

VALUE GENERATION

The relationships between our business segments and the value generated by their integration result in a stronger, more profitable and more growth-oriented business. Success in one area generates success in other segments. A key part of our growth strategy is to make investments in businesses that have meaningful links to AltaGas' existing activities. As we grow our asset base, we work to augment and enhance the connections between the new assets and our existing businesses and processes. Acquisitions are evaluated to ensure they are accretive to cash flow and net income. The expertise of our people in each segment enables the assessment of risks and opportunities as well as the successful execution and integration of acquisitions.

This continuous process enhances AltaGas' operations and earnings, adding to our financial strength and helping to position the Trust to act on profitable business growth opportunities.

energy to GROW OUR MARKETS

AltaGas' strategy is to deliver sustainable and increasing earnings and cash flow. We do so by growing and diversifying our businesses and markets, capitalizing on the integrated energy value chain.

85 Mmcf/d

increased processing capability

FIELD GATHERING AND PROCESSING

GROWTH STRATEGY

- Expand reach into B.C. and northern Alberta where there is strong producer activity, less infrastructure and where existing producer plants are fully utilized.
- Expand and extend our operating areas by acquiring and building additional skid-mounted facilities.
- Increase plant utilization in existing operating areas by adding new customers and optimizing facilities.
- Meet producer requirement for gathering and processing facilities in existing and new operating areas.

2006 GROWTH SNAPSHOT

- Added 15 Mmcf/d Clear Prairie and 10 Mmcf/d Clear Hills plants in western portion of WCSB.
- Constructed 20 Mmcf/d Princess plant which includes acid gas injection.
- Increased throughput capability at Prairie River, Rainbow Lake and Iron Creek by approximately 25 Mmcf/d.
- Increased interest in Pouce Coupe plant, adding 15 Mmcf/d of capacity.

48 Mmcf/d and 1,300 Bbls/d

increased capability

EXTRACTION AND TRANSMISSION

GROWTH STRATEGY

- Modify extraction plants to increase product recoveries.
- Increase extraction plant and transmission system utilization and expand existing facilities.
- Capture additional market share by acquiring increased ownership interests, constructing new facilities or acquiring existing facilities.
- Use existing infrastructure to offer and bundle marketing, transportation management and processing services with Energy Services and FG&P.

2006 GROWTH SNAPSHOT

- Increased AltaGas share of production capability at Edmonton extraction plant by 15 Mmcf/d and ethane production by 800 Bbls/d.
- Acquired additional interest in one Empress extraction plant, increasing AltaGas' share of net processing capacity by 15 Mmcf/d and production by 500 Bbls/d.
- Announced 18 Mmcf/d Cold Lake pipeline expansion to serve SAGD plant, an integrated project involving FG&P and Energy Services.

1,000MW

renewable generation development potential

13%

increase in energy management contracts

POWER GENERATION

GROWTH STRATEGY

- Acquire and develop power projects.
- Develop operational capability.
- Diversify by geography and fuel source.
- Capitalize on increasing demand for clean power by investing in renewable power project development in Canada and the northern U.S.
- Pursue additional contracts with rights to existing generation capacity (PPAs).

2006 GROWTH SNAPSHOT

- Higher power prices received resulted in 87 percent growth in segment operating income, despite expiry of 100-MW coal-fired Genesee PPA.
- Announced intention to develop renewable generation in Canada and the northern U.S.
- Established wind power development partnerships to pursue 1,000 MW of potential generation.

ENERGY SERVICES

GROWTH STRATEGY

- Increase market penetration of national energy management services in gas and electricity.
- Capitalize on market knowledge, expertise and customer relationships to grow gas services business and add incremental value to other segments.
- Add physical infrastructure such as gas storage capacity.

2006 GROWTH SNAPSHOT

- Renewed over 95 percent of energy management customers and increased contracts by 13 percent.
- Increased average wholesale volumes marketed by gas services business by almost 5 percent.
- Decline in Energy Service operating income primarily driven by declines in oil and gas production.
- Announced gas supply arrangement to serve Orion SAGD project in Cold Lake area.
- Arranged 30 Mmcf/d of incremental gas supply for Alberta extraction plants.

energy to **BE OUR BEST**

At AltaGas, we believe that living our core values is the best way to do business – 2006 was no exception. Every year we strive to improve our relationships with each of our stakeholders: unitholders, customers, employees, and the environment and communities where we live and work.

SAFETY AND ENVIRONMENT

We are environmental stewards who act knowing that safety is critical to our employees and communities.

Named one of Alberta's 350 safest companies.

CUSTOMERS

We connect with our customers' expectations and create value for our clients and AltaGas.

We provide energy management services to customers across Canada.

FINANCIALLY ASTUTE

We are accountable for delivering what we promise to our unitholders.

23 percent increase in earnings per unit.

energy to **LEAD**

David W. Cornhill,
Chairman, President and Chief Executive Officer

MESSAGE TO UNITHOLDERS

AltaGas is an integrated business with energy to grow. In 2006 we again experienced the benefits of our focus on key financial metrics as the Trust delivered its 13th consecutive net income record.

During the fourth quarter our 2006 net income surpassed the $100 million threshold. For us, it's the latest success on a business journey that has seen AltaGas grow earnings more than 150-fold since its launch in 1994.

We have repeatedly demonstrated our ability to manage and grow this integrated business at both the top line – revenues – and the bottom line – earnings. Last year was no exception. Net income for the full year was $115 million, or $2.06 per unit, a year-over-year increase of 27 percent. Funds from operations were $162 million or $2.92 per unit, annual growth of 25 percent. Return on equity was 22.7 percent, up from 18.4 percent in 2005. AltaGas' enterprise value reached $1.7 billion at year-end.

We are in business for the long term. Our four business segments are strong, competitive and growing. In pursuing our core activities, we drive expansion of our operations and earnings. The business segments interlink and integrate to form a single enterprise that is more than the sum of its parts, with internal business flow of more than $350 million per year. By commodity, this amounts to almost 275 gigawatt-hours of electricity and 94 billion cubic feet of natural gas per year.

2006 – GROWTH AND PERFORMANCE

AltaGas has come a long way since 1994 when we started with a team of 20 people, two short-term contracts, a tiny asset base and $37,000 in equity. Yet, significantly, we were profitable in our first year. By establishing and following sound business principles based on key financial metrics, we have succeeded in increasing net income ever since. Every year has been a record year, and AltaGas has grown to 530 employees and more than $1 billion in assets.

In 2006 the Trust delivered solid performance across the board. Three of four business segments increased operating income by capitalizing on high power prices, historically high "frac" spreads (the difference in value between the natural gas liquids we extract from the natural gas stream and the price of natural gas) and lower interest rates. Operating income increased despite the expiration of the Genesee contract and the spin-out of the Natural Gas Distribution segment in late 2005. We acted on 12 growth opportunities of varying scale, including five expansions, four new developments and three small acquisitions. Capital expenditures totalled $72 million.

The business segments' successes were achieved by pursuing growth in their core activities while carefully managing both opportunities and risks. For example,

Our 2006 net income surpassed the $100 million threshold on a business journey that has seen AltaGas grow earnings more than 150-fold since its launch in 1994.

Power Generation capitalized on high electricity prices and strong demand for peaking power to drive its earnings growth. But the segment also hedged pricing on about two-thirds of its output, protecting and stabilizing its cash flows.

Extraction and Transmission, whose key strengths include long-term contracts and long-life assets, also grew in 2006. The segment's $2.2 million expenditure on the enhanced ethane recovery project at the Edmonton Ethane Extraction Plant, boosted the ethane recovery factor to 90 percent and added 800 Bbls per day of marketable ethane to AltaGas, was achieved at high capital efficiency. This ensured the growth in volumes would be accretive to AltaGas' cash flow on a per unit basis.

Field Gathering and Processing, which operates in 29 natural gas-producing areas in western Canada, expanded its fleet of plants and its licensed capacity through $53 million in growth capital investment. An excellent example of the way FG&P acts on growth opportunities came at Prairie River. By installing new skid-mounted compression, we added processing capacity and increased production months sooner than would normally be possible. FG&P's core business involves fee-for-services and, as a result, the segment is not significantly exposed to natural gas price volatility. The segment mitigated some of the rising costs affecting the whole energy industry by continuing to shift more contracts to an operating cost flowthrough basis.

For Energy Services, one of the main drivers of success is the segment's superb customer service as demonstrated by our 95 percent customer renewal rate. Satisfied customers create a strong foundation for further growth. Commodity price volatility – like we are seeing today – actually drives this segment's business, because that's when consumers are most in need of impartial advice and sophisticated risk management, two of the things Energy Services does best.

Our energy to grow was reinforced in 2006 by our move into renewable power generation, through partnerships with two wind power developers, Aeolis Wind Power Corporation and GreenWing Energy Management Ltd. Renewable energy is a growing sector. It is also becoming a requirement in some North American jurisdictions. Renewable energy offers us the opportunity to diversify our power generation sources, to grow our asset base, and to extend the time horizon of our stable cash flows. Our first wind power development project, the Bear Mountain Wind Park in northeast B.C., is under development. We have signed a long-term energy purchase contract with BC Hydro, which will provide us with long-term cash flows from a creditworthy counterparty.

ALBERTA'S BOOM

Alberta's prolonged economic expansion has been demonstrably beneficial to businesses, the labour force and the province as a whole. It has also created cost pressures across the board and has challenged every business' ability to attract and retain employees.

We worked to meet these challenges and to limit cost increases. Positive measures included FG&P's continued move towards operating cost flowthrough contracts. On the human resources side, AltaGas has consistently been able to attract new people and we are seeing a labour force and management team of ever-higher quality.

Building and retaining such a great team stems in part from creating a positive work environment. Working at AltaGas is about far more than compensation. AltaGas is an intellectually challenging, socially responsible organization that offers opportunities for professional growth and career advancement in a great learning environment. We're

> Renewable energy offers us the opportunity to diversify our power generation sources, to grow our asset base, and to extend the time horizon for stable cash flows.

continually working to recognize our people's accomplishments and enhance employee benefits. In 2006 we held our first employee family event at the AltaGas Cup show jumping competition at Spruce Meadows. We enhanced our vacation allowance in 2006 and we improved our pension program in the previous year. In 2006, for the fifth consecutive year, we earned a place from MediaCorp as one of Canada's Top 100 Employers.

CORPORATE MATTERS

We previously announced our intention to implement CEO/CFO certification. This has been a substantial undertaking in its estimated cost of $3.5 million over two years and in the sustained efforts mounted by numerous staff in all our locations. We should see the dividends from more efficient processes and improved systems this year.

AltaGas already operated to high standards of financial reporting and control. The CEO/CFO certification process, which includes formalized procedures and written manuals, is driving our financial reporting and control processes and standards from a solid baseline up to best practices.

On January 15, 2007, I announced that I would remain as President and Chief Executive Officer of AltaGas and would continue to serve as Chairman of the Board of Directors. I also announced the appointment of Rick Alexander to Executive Vice President, Chief Operating Officer and Chief Financial Officer and of David Wright to Executive Vice President, both effective January 16, 2007. Rick joined the Trust as Senior Vice President Finance and Chief Financial Officer on May 1, 2006, while David Wright is a new member of our team. Rick and David bring extensive experience to AltaGas and will position the Trust for further success.

Rick is responsible for the day-to-day operations of all AltaGas operating business segments, as well as all financial matters. David Wright is responsible for corporate strategy and business development activities, as well as other corporate functions.

I believe that AltaGas' senior executive team includes a strong balance of talents that will enable us to continue executing our growth strategy.

SAFETY, ENVIRONMENT, HEALTH AND COMMUNITY

Safety is our number one priority. With 220 employees and contractors in the field, there is nothing more important than ensuring our people get home safely after work. In 2006 AltaGas again became one of about 350 out of Alberta's more than 128,000 employers to receive a Workplace Alberta Work Safety award. We consistently earn high scores on our safety audits and continue to develop our safety programs and procedures.

AltaGas has always had a strong commitment to environmental responsibility. In 2006 we achieved further success in this crucial area. We maintained our Platinum Level status with the Canadian Association of Petroleum Producers' Stewardship program. In addition, the 22 Phase I Assessments we performed during 2006 will help to ensure that our 170 field facilities follow environmental best practices. We are fulfilling our responsibility and are currently reclaiming four former operating sites.

We have driven AltaGas forward and upward by focusing on key metrics: earnings, return on equity and cash flow. This doesn't change whether our business is organized as a trust or a corporation.

Last year brought a record level of giving to the United Way of Calgary and Area, with total employee and corporate donations of $270,000, substantially more than in 2005. AltaGas received United Way Platinum status for the seventh consecutive year, signifying more than 90 percent employee participation.

We also continued our partnership with the Shock Trauma Air Rescue Society (STARS), involving a multi-year series of donations to support the acquisition of new helicopters and the extension of STARS' service range. In 2006 STARS opened its Grande Prairie base thanks in part to this funding commitment. The relationship with STARS benefits AltaGas' employees, as all of AltaGas' facilities have now been entered into the STARS Emergency Link Centre database, providing our field employees and their communities with life-saving air ambulances only a phone call away.

TAXATION OF INCOME TRUSTS

On October 31, 2006 the federal minister of finance announced a plan to subject existing income trusts to federal and provincial income tax effective in the 2011 tax year, a move adversely affecting the value of nearly all income trusts in the public markets.

The tax policy change has not changed our fundamental business strategy. AltaGas' vision for growth and financial success was never built around being tax-advantaged, but around creating value over the long term. We have driven AltaGas forward and upward by focusing on key metrics: earnings, return on equity and cash flow. This doesn't change whether our business is organized as a trust or a corporation. As an investment today, AltaGas offers excellent value even when evaluated as a corporation and compared to its main corporate competitors. The tax policy change reinforces the benefits of financial discipline and our longstanding practice of not over-paying for acquired assets.

With that said, AltaGas intends to become more active in government relations and public communications. The regulatory and governmental landscape is changing, and not necessarily for the better. We will work for favourable changes to business regulations.

DISTRIBUTIONS

In 2006 funds from operations of $2.92 per unit and cash distributions declared of just under $2 per unit resulted in a payout ratio of 68 percent. AltaGas' level of distributions results from specific business principles. Our philosophy of long-term earnings growth mandates that earnings grow faster than distributions. Our financial discipline and growth focus mean that we maintain distributions at approximately 70 to 80 percent of funds from operations. This approach creates stability and sustainability of distributions while providing capital for the Trust to continue growing. Given our strong financial metrics and continued growth, we see no need to decrease distributions. In fact, we will continue to look for opportunities to increase distributions as our financial capacity grows along with our overall business.

AN INTEGRATED BUSINESS WITH ENERGY TO GROW

AltaGas' goals for 2007 are to grow our businesses, grow our asset base and enhance the performance of drivers that we control. We will grow where we see value and can add value.

Our philosophy of long-term earnings growth mandates that earnings grow faster than distributions.

Right now we see opportunities to deploy capital in each of our business segments and to benefit from AltaGas' integration. The key challenge is executing deployment of our available capital to generate the expected returns over the desired time-frame. As always, we are guided by our mandate to create long-term value for unitholders.

FG&P's growth will focus on moving westward with the trend in conventional natural gas drilling, servicing Alberta's future coalbed methane production, and increasing market share. FG&P can exploit the innate strengths in its business model, such as the flexibility of quickly moving skid-mounted equipment to capture new opportunities.

Alberta's electricity demand is growing by more than 200 megawatts per year, putting upward pressure on prices and creating opportunities for Power Generation. The segment will also look to participate in additional renewable power projects. Prospects for success are strengthened by our strategic partnerships with wind power developers. We will continue to use our strong risk management processes to protect cash flows and distributions amid volatile commodity prices.

E&T also has opportunities for financially accretive growth as it works to increase ownership interests where available, raise efficiencies at existing facilities and provide natural gas pipelines in response to industry demand. Energy Services has prospects for organic growth by adding customers, and for physical infrastructure additions such as gas storage capacity.

In sum, AltaGas is poised to grow. We have the financial, intellectual and physical capacities to make it happen. Our financial resources include roughly $200 million in unutilized debt capacity and $45 million of retained cash flow. We'll continue to optimize our debt to capitalization ratio, balancing returns for investors against financial risk management. We evaluate opportunities to ensure they meet our investment criteria and, when they do, we act quickly to capture value. Our integrated business, AltaGas, has energy to grow.

As always, I'm impressed by and grateful for the performance of the well over 500 AltaGas employees and contractors in the field and in our offices. Every one of you contributed to our successes including our $100 million net income milestone. Thank you for another record year. You should be very proud of what you achieved.

Now, we can look forward together with optimism for AltaGas to continue delivering long-term, profitable and value-creating growth.

David W. Cornhill
Chairman, President and Chief Executive Officer

energy to **GOVERN**

CORPORATE GOVERNANCE

The members of the Board of Directors of AltaGas General Partner Inc. are elected by the Trust at the direction of the unitholders to manage or supervise the management, business and affairs of the Trust. It is our responsibility to ensure that the interests of unitholders and other stakeholders are properly represented. To that end, the Board of Directors has assumed responsibility for stewardship of the Trust and has developed standards and procedures for its operations that meet a high standard of governance. We regularly review the activities of the Trust with a view to ensuring its business affairs are conducted appropriately, with the honesty, integrity, transparency and accountability that unitholders expect. We are committed to continuing to direct the activities of the Trust to those high standards.

The annual meeting provides AltaGas' executives with the opportunity to communicate the Trust's goals and strategy to unitholders. The meeting offers unitholders the chance to hear first-hand from management and to understand AltaGas' strategy for seeking to continually increase unitholder value and grow the Trust. The Board of Directors and AltaGas' management team encourage you to attend the annual meeting either in person in Calgary or through the live webcast that can be viewed at www.altagas.ca. The annual meeting will be held at 3:00 p.m. MDT on Thursday, April 26, 2007 at Bankers Hall Auditorium, Lower Level A/P3, 315 - 8th Avenue S.W., Calgary, Alberta.

On behalf of the Board of Directors:

Myron F. Kanik
Lead Director

AltaGas believes that good governance improves performance and benefits all unitholders. AltaGas is committed to a high standard of governance. The following is a summary of the Trust's Governance Practices. A more detailed description of the Trust's practices can be found in the Trust's Information Circular filed on the SEDAR system.

STATEMENT OF GOVERNANCE PRACTICES

Mandate of the Board

The Board of Directors of the General Partner exercises overall responsibility for the management and supervision of the affairs of the Trust. This includes the appointment of the President and Chief Executive Officer and senior officers of AltaGas Ltd. and AltaGas General Partner Inc., approval of their compensation and monitoring of the President and Chief Executive Officer's performance.

The Board of Directors also reviews and approves the annual strategic plan. Key objectives, as well as quantifiable operational and financial targets, and processes for the identification, monitoring and mitigation of principal business risks are incorporated into the annual strategy review.

The Board of Directors ensures that a process is established that adequately provides for succession planning, including the appointment, training and monitoring of senior management.

In 2006, the Board of Directors reviewed and ratified the Trust's Disclosure Policy and Risk Management Policy.

BOARD COMPOSITION

The Board currently comprises seven Directors, six of whom are independent. David W. Cornhill, Chairman, President and Chief Executive Officer of AltaGas General Partner Inc., is the only member of the Board of Directors who is also a member of management.

Board Committees

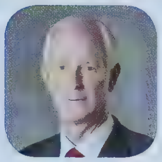
The Board has four standing committees: Governance; Audit; Environment and Safety; and Human Resources and Compensation. The Governance, Audit and Human Resources and Compensation committees are composed exclusively of non-management, independent directors. The Environment and Safety Committee includes a majority of non-management, independent directors. The Chairman, President and Chief Executive Officer of AltaGas General Partner Inc. serves on the Environment and Safety Committee. Each of the committees has a Board of Directors-approved mandate that prescribes its composition and responsibilities.

Governance Committee (GC)

The Governance Committee is responsible for reviewing, reporting and providing recommendations for improvement to the Board with respect to all aspects of

BOARD OF DIRECTORS

David W. Cornhill
Chairman, President and Chief Executive Officer
Member of the ESC

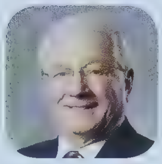


Allan L. Edgeworth
Director
Independent director; Member of the AC and ESC

Denis C. Fonteyne
Director
Independent director; Chair of the ESC and Member of the HRCC

Daryl H. Gilbert
Director
Independent director; Member of the AC and HRCC

Robert B. Hodgins
Director
Independent director; Chair of the AC and Member of the GC



Myron F. Kanik
Lead Director
Independent director; Chair of the GC and of the HRCC

David F. Mackie
Director
Independent director; Member of the GC and HRCC

governance. The Committee is responsible for identifying individuals qualified to become members of the Board of Directors, and recommends to the Board of Directors proposed nominees for election to the Board of Directors. The Committee reviews and recommends compensation for Directors. Annually, the Governance Committee formally assesses the effectiveness of the Board of Directors and the Committees of the Board of Directors. As well, the Committee is responsible for the orientation and education of new members of the Board of Directors and continuing development of existing members of the Board of Directors.

Audit Committee (AC)

The Audit Committee comprises three independent and financially literate Directors who oversee the Trust's financial reporting process on behalf of the Board of Directors. The Audit Committee reviews, reports and provides recommendations to the Board of Directors on the annual and interim financial statements, including the completeness and accuracy of financial reporting of the Trust; the adequacy of risk management processes; the adequacy of its internal control system for financial reporting and disclosure; and the appointment, terms of engagement, provision of non-audit services and proposed fees of the independent auditor. At every Audit Committee meeting, the Committee has the opportunity to meet with the independent and internal auditors without management present.

The Chair of the Audit Committee is Robert B. Hodgins, previously Chief Financial Officer of Pengrowth Energy Trust, Treasurer of Canadian Pacific Limited and Chief Financial Officer of TransCanada PipeLines Limited. Mr. Hodgins has the strong financial background key to this role.

Environment and Safety Committee (ESC)

The Environment and Safety Committee is responsible for reviewing, reporting and making recommendations to the Board of Directors on the Trust's policies and procedures with respect to the environment and occupational health and safety.

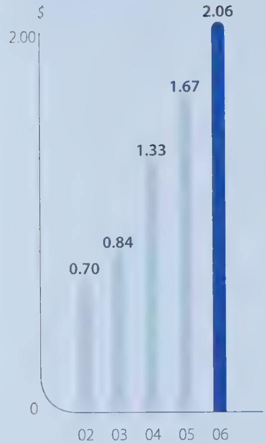
The Trust is committed to being a steward of the environment and to the health and safety of its employees.

Human Resources and Compensation Committee (HRCC)

The Human Resources and Compensation Committee reviews, reports and provides recommendations to the Board of Directors on the compensation of the President and Chief Executive Officer and the appointment and compensation of senior corporate officers, succession plans, the compensation policy for all other employees and the approval of all grants of unit options. In 2006, AltaGas adopted a Code of Business Ethics, a copy of which can be viewed on our website. AltaGas is committed to operating its businesses in an ethical manner.

energy to GROW FINANCIALLY

NET INCOME PER BASIC UNIT
$



Cumulative average growth of 31%

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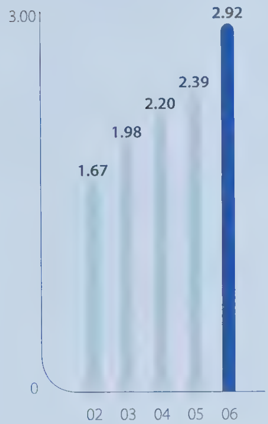
FUNDS FROM OPERATIONS PER BASIC UNIT
$



Cumulative average growth of 15%

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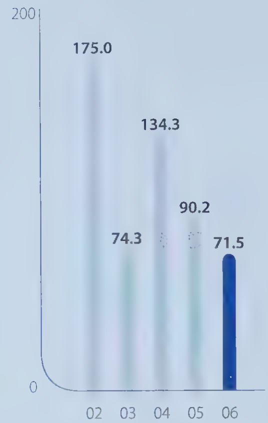
INVESTED CAPITAL
$ millions



Total of $545.3 million invested in last five years

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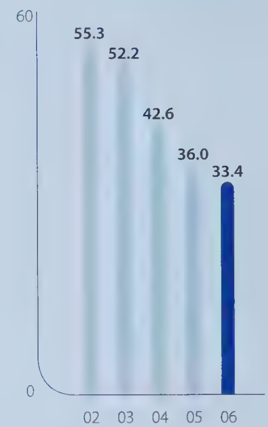
DEBT AS A PERCENT OF TOTAL CAPITALIZATION
%



Below target of 40-45% to support growth strategy

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$114.5 million **net income**

$161.7 million **funds from operations**

$1.1 billion **total assets**

$265.5 million **total debt**

MD&A CONTENTS

OVERVIEW

SEGMENTS

LIQUIDITY

OTHER

2006 PERFORMANCE DRIVERS

- Higher power prices received on both hedged and unhedged power volumes and lower power transmission costs in the Power Generation segment.
- Higher natural gas liquids fractionation spreads in the extraction business.
- In Field Gathering and Processing, throughput was impacted by increases from new facilities and higher well tie-ins in some areas and volume declines and operational interruptions in other areas.
- Lower interest expense due to lower average interest rates and lower debt balances.
- Non-cash future income tax benefit of $6.6 million as a result of a reduction in federal and Alberta corporate income tax rates.
- Expiry of the 100-MW Genesee power contract and the November 2005 spin-out of the Natural Gas Distribution segment partially offset earnings increases, as did the 2005 one-time contributions related to the Trust's ownership of Taylor NGL Partnership units.

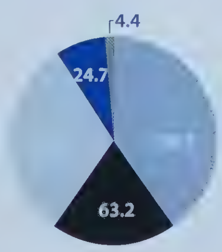
$318.9 million
net revenue

$126.7 million
operating income

$71.5 million
invested capital

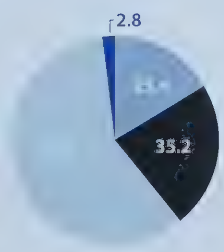
$6.1 million
maintenance capital

NET REVENUE
$ millions



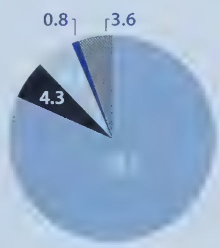
Before intersegment eliminations Page 82

OPERATING INCOME
$ millions



Excluding Corporate segment Page 23

INVESTED CAPITAL
$ millions



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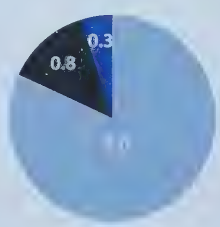
MAINTENANCE CAPITAL
$ millions



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MANAGEMENT'S DISCUSSION AND ANALYSIS

The Management's Discussion and Analysis (MD&A) of operations and financial statements presented herein reports on a continuity-of-interests accounting basis which recognizes AltaGas Income Trust (AltaGas or the Trust) as the successor to AltaGas Services Inc. (ASI). This MD&A dated March 8, 2007 is a review of the results of operations and the liquidity and capital resources of the Trust for the year ended December 31, 2006, compared to 2005. It should be read in conjunction with the accompanying audited Consolidated Financial Statements and notes thereto of the Trust for the year ended December 31, 2006.

This MD&A contains forward-looking statements. When used in this MD&A the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "seek", "propose", "estimate", "expect", and similar expressions, as they relate to the Trust or an affiliate of the Trust, are intended to identify forward-looking statements. In particular, this MD&A contains forward-looking statements with respect to, among other things, business objectives, expected growth, results of operations, performance, business projects and opportunities and financial results. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Such statements reflect the Trust's current views with respect to future events based on certain material factors and assumptions and are subject to certain risks and uncertainties including without limitation, changes in market competition, governmental or regulatory developments, changes in tax legislation, general economic conditions and other factors set out in the Trust's public disclosure documents. Many factors could cause the Trust's actual results, performance or achievements to vary from those described in this MD&A, including without limitation those listed above. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this MD&A as intended, planned, anticipated, believed, sought, proposed, estimated or expected, and such forward-looking statements included in this MD&A herein should not be unduly relied upon. These statements speak only as of the date of this MD&A. The Trust does not intend, and does not assume any obligation, to update these forward-looking statements except as required by law. The forward-looking statements contained in this MD&A are expressly qualified as cautionary statements.

Additional information relating to AltaGas can be found on its website at www.altagas.ca. The continuous disclosure materials of the Trust, filed as AltaGas Services Inc. prior to May 1, 2004, including its annual MD&A and audited financial statements, Annual Information Form, Information Circular and Proxy Statement, material change reports and press releases issued by the Trust, are also available through the Trust's website or directly through the SEDAR system at www.sedar.com.

ALTAGAS INCOME TRUST

The material businesses of the Trust are operated by AltaGas Ltd., AltaGas Operating Partnership, AltaGas Limited Partnership, AltaGas Pipeline Partnership, as well as PremStar Energy Canada Limited Partnership (PremStar) and ECNG Energy L.P. (collectively the operating subsidiaries). AltaGas Utilities Inc. was owned by the Trust until the November 17, 2005 spin-out of the Natural Gas Distribution (NGD) segment. The cash flow of the Trust is solely dependent on the results of the operating subsidiaries and is derived from operating income earned from partnership interests held by AltaGas Holding Limited Partnership No. 1 (AltaGas LP #1), from interest earned on loans to the operating subsidiaries and from dividends or returns of capital from equity interests held within the Trust structure.

AltaGas General Partner Inc., through its Board of Directors, the members of which are elected by the Trust at the direction of the holders of the units, has been delegated by the trustee of the Trust to manage or supervise the business and affairs of the Trust. AltaGas Ltd. provides all management, administrative and operating services to the Trust and its subsidiaries.

OVERVIEW OF THE BUSINESS AND STRATEGY

AltaGas uses its energy infrastructure and in-depth market knowledge to move energy from its source to end-users. AltaGas' objective is to grow its asset base, increase operating efficiency and utilization of its energy infrastructure and link the components of its integrated energy business to increase unitholder value.

AltaGas' integrated energy business comprises four operating segments:

- Field Gathering and Processing (FG&P) includes natural gas gathering pipelines and processing facilities.
  - Gathering systems move natural gas from producing wells to processing facilities;
  - Processing facilities remove impurities and certain hydrocarbon components from natural gas, in addition to compressing the gas to meet downstream pipelines' operating specifications for transportation;

- Extraction and Transmission (E&T) includes ethane and natural gas liquids (NGLs) extraction plants and natural gas and condensate transmission pipelines.
  - Extraction plants straddle major natural gas transmission pipelines and reprocess the natural gas to extract and recover ethane and NGLs;
  - Transmission pipelines deliver natural gas and condensate to distribution systems, end-users or other downstream pipelines;
- Power Generation consists of 353 MW of coal-fired generation under power purchase arrangements (PPAs), 25 MW of gas-fired power output under a lease arrangement and interests in two partnerships to develop wind power;
- Energy Services includes energy management services, gas services, and oil and natural gas production.
  - Energy management provides energy (gas and electricity) consulting and supply management services to industrial, agricultural, commercial and institutional end-users;
  - The gas services business buys and resells power and gas supply, gas transportation and storage, and markets gas for producers;
  - AltaGas holds a small portfolio of oil and natural gas producing assets with output sold on the spot market.

STRATEGY

AltaGas' has successfully executed its strategy since inception to become one of Canada's leading integrated energy businesses. The Trust's strategy is to deliver sustainable and increasing earnings and cash flow through growth and diversification of its businesses, which capitalize on the integrated energy value chain. Energy value chain integration is the integration of the gathering, processing, transportation and marketing of natural gas, generation and sale of electric power and petroleum from the source to the end-user.

By positioning the Trust strategically along the energy value chain, AltaGas links energy producers to energy users. AltaGas has expanded its business since inception to serve the growing demand for natural gas and power and has developed a portfolio of assets and services in business and geographic areas in which it has competitive advantages and expertise.

AltaGas pursues opportunities along the energy value chain that offer strong financial returns and growth potential. Despite the recent softening in natural gas prices, AltaGas' management believes that North America's natural gas producing regions will continue to require significant investment in drilling and field development to support the levels of production needed to meet long-term demand for natural gas as consuming markets continue to compete for supply. Management also believes that the long-term fundamentals of the power business are strong. North American demand for power is expected to continue growing, with an emphasis on renewable power. In Alberta, marginal supply additions, strong economic growth and the upcoming retirement of older thermal power plants is likely to result in high power prices.

AltaGas owns and operates energy infrastructure in both the natural gas and power sectors and has in-depth knowledge and expertise in the natural gas and power markets where it operates. AltaGas employs its assets and expertise to capture value effectively and efficiently, linking the assets, the gas and power interdependencies, and the arbitrage opportunities across these commodities and services to enhance value for its customers and unitholders.

The Trust's objectives are to:

- Grow its energy infrastructure and services businesses through expansions and acquisitions in Canada and the northern United States;
- Operate new and existing assets to provide stable and predictable cash flow;
- Focus on energy businesses along the value chain that are diversified in terms of their revenue source, contractual terms, exposure to industry cycles and geographic location;
- Build on the current mix of energy assets and services with a continued focus on predictable, long-term cash flow horizons using cost-of-service, fixed-fee, and margin-based contract terms and with minimal or managed exposure to commodity prices; and
- Continue to evaluate opportunities and expand its integrated businesses in a manner that is accretive to unit value, ensuring concentrations of risk are minimized.

In 2006 the Trust continued to grow its integrated energy business through internal expansions and acquisitions of energy infrastructure assets. To position itself for continued growth, AltaGas also pursued its strategy to develop renewable energy power projects in Canada and the northern United States by investing in partnerships with wind power developers.

2006 HIGHLIGHTS

During 2006, AltaGas:

- Generated net income of $114.5 million ($2.06 per unit) compared to $90.3 million ($1.67 per unit) in 2005;
- Reported EBITDA[(1)] of $173.1 million ($3.12 per unit), up from $155.5 million ($2.88 per unit) in 2005. EBITDA in 2005 included $9.2 million of gains related to the investment in units of Taylor NGL Limited Partnership (Taylor) and $13.0 million related to the NGD business;
- Generated cash from operations of $146.9 million ($2.65/unit) compared to $112.3 million ($2.08/unit) in 2005;
- Generated funds from operations[(1)] of $161.7 million ($2.92/unit) compared to $129.0 million ($2.39/unit) in 2005;
- Increased monthly distributions by 6 percent from $0.16 to $0.17 per unit;
- Declared cash distributions in 2006 of $110.8 milion ($1.995/unit) compared to $100.0 million ($1.85/unit) in 2005;
- Invested $53.3 million in FG&P facilities to increase processing capacity primarily in areas with high producer activity and limited processing capacity;
- Announced the expansion of the Cold Lake natural gas transmission system by 18 Mmcf/d;
- Formed the Bear Mountain Wind Limited Partnership (BMWLP) with Aeolis Wind Power Corporation (Aeolis). The partnership was one of the winning bidders in the BC Hydro Fiscal 2006 Open Call for Power. The proposed 120-MW Bear Mountain Wind Park is located near Dawson Creek in northeast British Columbia and is expected to be in service in 2009; and
- Formed the GreenWing Energy Development Limited Partnership (GEDLP) with GreenWing Energy Management Ltd. (GreenWing) to pursue a portfolio of power projects in North America with the potential to develop approximately 800 MW of generation capacity.

[1] Non-GAAP financial measure. See discussion in Non-GAAP Financial Measures section of this MD&A.

CONSOLIDATED RESULTS

($ millions)	2006	2005	2004
Revenue	**1,362.6**	1,502.3	864.6
Net revenue[1]	**318.9**	296.9	250.4
Net income	**114.5**	90.3	65.8
EBITDA[1]	**173.1**	155.5	133.4
Operating income[1]	**126.7**	108.1	91.6
Total assets	**1,109.6**	1,068.3	1,108.6
Total long-term liabilities	**340.5**	335.5	323.7
Net additions (disposals) of capital assets	**70.5**	(139.4)	101.6
Dividends/distributions declared[2][3]	**110.8**	100.0	66.7
Cash flows			
Cash from operations	**146.9**	112.3	147.7
Funds from operations[1]	**161.7**	129.0	108.6
Distributable cash[1]	**155.6**	121.0	102.2

($ per unit)			
Net income	**2.06**	1.67	1.33
EBITDA[1]	**3.12**	2.88	2.70
Dividends/distributions declared[2][3]	**1.995**	1.85	1.31
Cash flows			
Cash from operations	**2.65**	2.08	2.99
Funds from operations[1]	**2.92**	2.39	2.20
Distributable cash[1]	**2.81**	2.24	2.07
Units outstanding (millions)			
Weighted average number of units outstanding for the period (basic)	**55.5**	54.0	49.4
End of period	**56.4**	54.6	53.2

(1) Non-GAAP financial measure. See discussion in Non-GAAP Financial Measures section of this MD&A.

(2) Distributions declared of $0.17 per unit per month commencing in August 2006. From March 2006 to July 2006 distributions of $0.165 per unit per month were declared. From August 2005 to February 2006 distributions of $0.16 per unit per month were declared. From May 2004 to July 2005 distributions of $0.15 per unit per month were declared. In the first quarter 2004 dividends of $0.11 per share were declared.

(3) Excludes share distribution as a result of the spin-out of the NGD segment in November 2005, providing an additional non-cash distribution of $0.54 per unit.

2006 CONSOLIDATED FINANCIAL REVIEW

Net income in 2006 was $114.5 million ($2.06 per unit) compared to $90.3 million ($1.67 per unit) in 2005. The increase was due to higher power prices received on both hedged and unhedged power volumes, lower power transmission costs, higher NGL fractionation spreads (frac spreads), higher extraction volumes and lower interest expense, partially offset by higher operating and administrative expense and higher income taxes.

In addition, the Trust recorded a $6.6 million non-cash future income tax benefit in 2006 as a result of a reduction in federal and Alberta corporate income tax rates. Net income in 2005 included one-time after-tax contributions of $7.5 million related to the Trust's ownership of Taylor units, a full-year contribution from the Genesee power contract and the contribution from the NGD segment which was spun out on November 17, 2005.

In the Power Generation, Energy Services and Extraction and Transmission segments, net revenue, which is revenue less the cost of commodities purchased for sale and shrinkage, is a better reflection of performance than revenue, as changes in the market price of power and natural gas affect both revenue and cost of sales.

Net revenue for 2006 was $318.9 million compared to $296.9 million in 2005. The increase was mainly due to higher prices received on the sale of power and lower power transmission costs ($42.2 million), new facilities, higher processing fees and higher operating cost recoveries in the FG&P segment ($15.1 million), higher NGL frac spreads and higher volumes processed in the extraction business ($7.0 million), higher equity earnings in the Corporate segment ($3.0 million), the acquisition of the assets and liabilities of iQ2 Power Corporation (iQ2) in late 2005 ($2.2 million) and $2.1 million higher net revenue from the gas-fired peaking plants. The increases in net revenue were partially offset by the spin-out of the NGD business in November 2005 ($29.0 million), lower throughput in the FG&P segment ($5.2 million), the expiration of the Genesee power contract in March 2006 ($2.5 million) and $1.6 million lower contribution from the oil and gas properties. In 2005 net revenue included one-time contributions of $8.6 million related to the Trust's ownership of Taylor units.

Operating and administrative expense for 2006 was $145.8 million, compared to $141.4 million in 2005. The increase was due to higher administrative and compensation costs, additional costs due to new FG&P facilities and the acquisition of iQ2. The increases were partially offset by the spin-out of the NGD segment which reported operating and administrative costs of $16.0 million in 2005. Increased third-party costs of approximately $1.0 million were incurred in 2006 compared to 2005 to meet new certification requirements for reporting issuers mandated by the Canadian Securities Administrators.

Amortization expense for 2006 was $46.4 million compared to $47.4 million last year. The decrease was due to the spin-out of the NGD segment which reported $6.8 million in amortization expense in 2005, partially offset by increases related to the growth in capital assets resulting from acquisitions and internal expansion projects, higher depletion expense related to the Trust's oil and gas properties and higher amortization related to energy services contracts and relationships. In fourth quarter 2006 AltaGas recorded a goodwill impairment of $0.6 million related to a non-core investment.

Interest expense in 2006 was $13.3 million compared to $19.1 million in 2005. The decrease was due to lower average debt balances (2006 – $274.1 million, 2005 – $326.1 million) as a result of $85.4 million in debt repayment in late 2005 using the proceeds from the spin-out of the NGD segment and due to higher funds from operations. Also contributing to the lower interest expense was a lower average borrowing rate of 4.9 percent in 2006, compared to 5.6 percent in 2005, mainly due to the August 2005 refinancing of term debt at lower rates.

Income tax recoveries for 2006 were $1.1 million compared to recoveries of $1.3 million in 2005. Income tax recoveries decreased as a result of higher net income before tax in 2006, partially offset by a non-cash future tax benefit of $6.6 million that resulted from federal and Alberta income tax rate reductions in 2006. Income taxes reported in 2005 also included an expense of $1.1 million related to the NGD segment, an adjustment of future tax balances that resulted in a recovery of $1.6 million and a lower effective tax rate in respect of the Taylor capital gain reported in 2005.

The Trust expects approximately 73 percent of the cash distributions declared in 2006 to be taxed as income with the remaining 27 percent classified as return of capital.

2005 CONSOLIDATED FINANCIAL REVIEW

Net income for the year ended December 31, 2005 was $90.3 million ($1.67 per unit), compared to $65.8 million ($1.33 per unit) for the year ended December 31, 2004. Net income increased by 37 percent due to full-year operations of 2004 acquisitions, higher power prices received, gains on the disposition of investments, lower interest expense as a result of lower average debt balances and lower interest rates, and lower income taxes. The increases to net income were partially offset by higher operating and administrative and amortization costs, higher power transmission and generation costs and the spin-out of the NGD business in the fourth quarter.

Net income in 2005 included one-time after-tax contributions of $7.5 million related to the Trust's investment in Taylor.

On a consolidated basis, net revenue for 2005 was $296.9 million, an increase of 19 percent from $250.4 million in 2004. The increase was due to the full-year impact of the third quarter 2004 acquisition of the Edmonton Ethane Extraction Plant (EEEP, $10 million), the full-year impact of the fourth quarter 2004 acquisition of PremStar ($11 million), higher average prices received on power sales ($10 million), and gains from the disposition of Taylor units ($9.2 million). In the FG&P segment, expansions and acquisitions, higher processing fees and higher operating cost recoveries increased net revenue by approximately $8 million. These increases were slightly offset by the spin-out of the NGD segment on November 17, 2005 ($2 million), and the reduction of equity income related to the reduction in ownership interest in the Taylor investment.

Operating and administrative expense for 2005 were $141.4 million, compared to $117.0 million in 2004. The net increase in operating and administrative expense of $24.4 million was due to growth in operations, higher operating costs which are recovered from customers, increased power transmission and generation costs, higher repair and maintenance costs, higher general corporate expenses to support the growth of the Trust and costs incurred to meet new certification requirements for reporting issuers mandated by the Canadian Securities Administrators. The increases were offset by lower costs resulting from the spin-out of the NGD segment.

Amortization expense for 2005 increased to $47.4 million from $41.8 million in 2004. The higher expense was mainly due to increases in capital assets resulting from acquisitions and internal expansion projects, and higher depletion expense related to the Trust's oil and gas properties.

Interest expense for 2005 was $19.1 million, a decrease of $2.1 million from $21.2 million in 2004. The decrease was due to lower average debt balances (2005 – $326.1 million, 2004 – $359.6 million) resulting from the Trust's equity issue in June 2004, proceeds related to the November 17, 2005 spin-out of the NGD segment used to repay $85.4 million of debt, and to higher funds generated from operations in 2005, partially offset by interest on a capital lease acquired in the third quarter of 2004. Also contributing to the lower interest expense were lower average borrowing rates on existing credit facilities due to a higher proportion of outstanding debt being underpinned by interest rate swaps, and reduced interest costs associated with the issuance of the medium-term notes (MTNs) issued in August 2005.

As a result of AltaGas' conversion to an income trust, and consequently intercompany interest expense reducing taxable income, amortization expense exceeded capital cost allowance claimed, resulting in a reversal of the Trust's future income tax liability.

In 2005 the Trust recorded an income tax recovery of $1.3 million compared to an income tax expense of $4.6 million in 2004. The decrease in income tax expense reflected AltaGas as an income trust for a full year compared to eight months in 2004. In addition, the 2005 income tax expense was impacted by an adjustment of future tax balances as well as an additional tax expense in respect of the spin-out of the NGD business. Current income tax expense was recorded as a result of the NGD segment, which operated as regulated businesses under utility board regulation until its spin-out in November 2005, as well as Large Corporations Tax for all the Trust's subsidiaries.

NON-GAAP FINANCIAL MEASURES

This MD&A contains references to certain financial measures that do not have a standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP) and may not be comparable to similar measures presented by other entities. The non-GAAP measures and their reconciliation to GAAP financial measures are shown below. All of the measures have been calculated consistent with previous disclosures.

NET REVENUE *($ millions)*	**2006**	2005	2004
Net revenue	**318.9**	296.9	250.4
Add: Cost of sales	**1,043.7**	1,205.4	614.2
Revenue (GAAP financial measure)	**1,362.6**	1,502.3	864.6

Net revenue, which is revenue less the cost of commodities purchased for sale and shrinkage, is a better reflection of performance than revenue, as changes in the market price of natural gas and power affect both revenue and cost of sales.

OPERATING INCOME *($ millions)*	**2006**	2005	2004
Operating income	**126.7**	108.1	91.6
Add (deduct): Interest expense	**(13.3)**	(19.1)	(21.2)
Income tax recovery (expense)	**1.1**	1.3	(4.6)
Net income (GAAP financial measure)	**114.5**	90.3	65.8

Operating income is a measure of the Trust's profitability from its principal business activities prior to how these activities are financed or how the results are taxed. Operating income is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net revenue less operating and administrative expenses and amortization of capital assets.

EBITDA *($ millions)*	**2006**	2005	2004
EBITDA	**173.1**	155.5	133.4
Add (deduct): Amortization and goodwill impairment	**(46.4)**	(47.4)	(41.8)
Interest expense	**(13.3)**	(19.1)	(21.2)
Income tax recovery (expense)	**1.1**	1.3	(4.6)
Net income (GAAP financial measure)	**114.5**	90.3	65.8

EBITDA is a measure of the Trust's operating profitability. EBITDA provides an indication of the results generated by the Trust's principal business activities prior to accounting for how these activities are financed, assets are amortized or how the results are taxed. EBITDA is calculated from the Consolidated Statements of Income and Accumulated Earnings and is defined as net revenue less operating and administrative expenses.

FUNDS FROM OPERATIONS *($ millions)*	**2006**	2005	2004
Funds from operations	**161.7**	129.0	108.6
Add (deduct): Net change in non-cash working capital and asset retirement obligations settled	**(14.8)**	(16.7)	39.1
Cash from operations (GAAP financial measure)	**146.9**	112.3	147.7

Funds from operations is used to assist management and investors in analyzing operating performance without regard to changes in the Trust's non-cash working capital in the period. Funds from operations as presented should not be viewed as an alternative to cash from operations, or other cash flow measures calculated in accordance with GAAP. Funds from operations is calculated from the Consolidated Statements of Cash Flows and is defined as cash provided by operating activities before changes in non-cash working capital and expenditures incurred to settle asset retirement obligations.

DISTRIBUTABLE CASH *($ millions)*		**2006**	2005	2004
Distributable cash		**155.6**	121.0	102.2
Add (deduct):	Maintenance capital expenditures	**6.1**	8.0	6.4
	Net change in non-cash working capital and asset retirement obligations settled	**(14.8)**	(16.7)	39.1
Cash from operations (GAAP financial measure)		**146.9**	112.3	147.7

Distributable cash is used by management to supplement cash from operations as an estimate of the amount which is available for distribution to unitholders. Distributable cash is defined as cash from operations less expenditures for maintenance capital and asset retirement obligations settled in the period. Maintenance capital expenditures are incurred to sustain the productive capacity of the Trust's assets and are not incurred evenly throughout the year. Distributable cash is not a defined financial measure under GAAP and distributable cash cannot be assured. The Trust's calculation of distributable cash may differ from similar calculations used by other entities.

References to EBITDA, net revenue, operating income, funds from operations and distributable cash throughout this document have the meanings set out above.

RESULTS OF OPERATIONS BY SEGMENT

OPERATING INCOME *($ millions)*	**2006**	2005
Field Gathering and Processing	**25.4**	24.1
Extraction and Transmission	**35.2**	30.4
Power Generation	**90.9**	48.7
Energy Services	**2.8**	5.6
Natural Gas Distribution	**–**	6.2
Corporate	**(27.6)**	(6.9)
	126.7	108.1

FIELD GATHERING AND PROCESSING

39% of operating costs recovered.

The FG&P segment consists of 74 gathering and processing facilities in 29 operating areas located in western Canada and the Northwest Territories and approximately 6,000 km of gathering lines upstream of processing facilities that deliver natural gas into downstream pipeline systems that feed North American natural gas markets.

AltaGas operates 71 of its 74 processing facilities and has a total gross licensed processing capacity of 1.0 Bcf/d, including 252 Mmcf/d of sour gas processing capacity.

The gathering systems move natural gas on behalf of producers from the wellhead to processing facilities where impurities and certain hydrocarbon components from natural gas are removed and the gas is compressed to meet the operating specifications of

downstream pipeline systems that deliver gas to domestic and export energy markets. AltaGas focuses on owning and operating smaller, moveable natural gas processing facilities with processing capacity of under 50 Mmcf/d which distinguishes it from most of its competitors in western Canada.

The FG&P segment's main business drivers are volume throughput, gathering and processing fees and operating costs. Volume throughput is impacted by new well tie-ins, reactivations, re-completions, well optimizations performed by producers and natural production declines in AltaGas' operating areas.

RESULTS OF OPERATIONS

FINANCIAL RESULTS *($ millions)*	**2006**	2005
Revenue	**139.1**	131.8
Net revenue	**129.7**	120.1
Operating and administrative	**80.1**	75.3
Amortization	**23.6**	20.7
Goodwill impairment	**0.6**	–
Operating income	**25.4**	24.1

OPERATING STATISTICS	**2006**	2005
Capacity (Mmcf/d)(1)	**1,021**	962
Throughput (gross Mmcf/d)(2)	**549**	573
Throughput (gross annual Mmcf/d)(3)	**555**	563
Capacity utilization (%)(3)	**54**	60
Average working interest (%)(1)	**92**	90

(1) As at December 31.

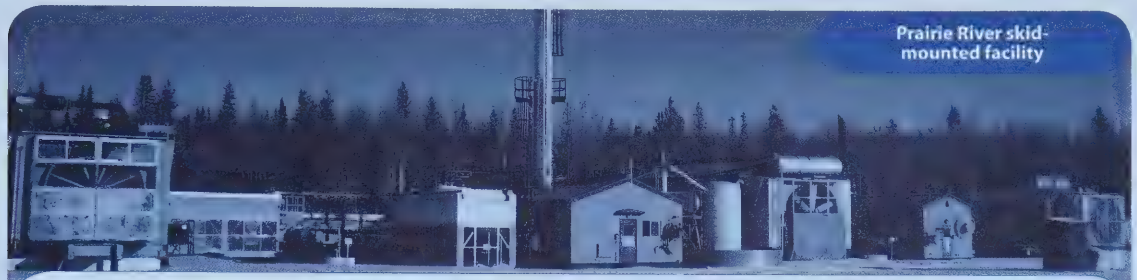
(2) Fourth quarter average.

(3) Average for the period.

Operating income in the FG&P segment for 2006 was $25.4 million compared to $24.1 million in 2005. Operating income increased by $2.7 million as a result of new facilities, $2.6 million due to higher rates and $2.5 million from higher operating cost recovery. These increases were a direct result of AltaGas' strategy to manage the risk of volume declines by adding new facilities, increasing processing rates and moving to more contracts that allowed AltaGas to flow through operating costs. The increases in operating income in 2006 were partially offset by lower producer activity and operational and third-party interruptions at Bantry and Rainbow Lake ($5.3 million) which persisted throughout the year, volume declines ($2.0 million), higher amortization of $1.3 million due to expansions and the goodwill write-down of $0.6 million related to a non-core investment. In 2005 corporate costs of $3.3 million were charged to the segment and $0.9 million of positive equalizations of operating costs were reported. After taking into consideration the change in corporate cost allocations and a positive adjustment of $0.9 million associated with a co-owned facility in 2005, operating income decreased by $1.0 million.

Throughput in 2006 averaged 555 Mmcf/d, a decrease of 8 Mmcf/d from 2005. The 8 Mmcf/d decline was due to 26 Mmcf/d lower throughput from existing facilities, offset by an increase from new facilities of 18 Mmcf/d. Throughput in the South district decreased by 1 percent or 4 Mmcf/d in 2006. The addition of the new Princess plant increased volumes by 7 Mmcf/d which offset lower throughput due to natural declines and slightly lower producer activity. The South district continued to be an area of relatively stable volumes in 2006.

Volumes processed in the North district also decreased by 1 percent, or 4 Mmcf/d, in 2006. The addition of the new plants at Clear Prairie and Clear Hills and the full-year impact of the Blair Creek plant increased throughput by 11 Mmcf/d which offset the effects



of natural declines, slightly lower producer activity and third-party operational issues. AltaGas expects the North district to continue to be an area of growth opportunity. While AltaGas experienced lower throughput in 2006 compared to 2005, results remained relatively stable as a result of the contracting and growth strategy employed to offset the financial impact of lower throughput.

Utilization in 2006 was 54 percent, compared to 60 percent reported in 2005. Approximately half of the decrease was due to planned and unplanned operational interruptions, mainly at Bantry, upstream producer disruptions at Rainbow Lake and the slowdown experienced in producer drilling and well tie-ins late in 2006, as well as natural declines in some of the operating areas.

The remaining decrease in utilization was due to the timing of volumes associated with the completion of new facilities, as well as higher capacity licensed than processing capability built in order to meet the demand for processing capability in the future.

Revenue in the FG&P segment in 2006 was $139.1 million compared to $131.8 million in 2005. New facilities contributed $9.4 million to revenue in 2006. The increase was also due to higher flowthrough operating costs ($3.1 million) and higher fees ($2.6 million). The increases were partially offset by operational interruptions and upstream disruptions at the Bantry and Rainbow Lake facilities ($3.2 million), lower throughput volumes ($2.0 million) and lower product revenue ($3.2 million).

Operating and administrative expense in the FG&P segment in 2006 was $80.1 million compared to $75.3 million in 2005. The increase was due to additional costs of $5.1 million related to new facilities, general cost escalations of approximately $2.3 million and higher power costs of $0.7 million. A first-quarter 2005 positive adjustment of $0.9 million associated with a co-owned facility also contributed to the year-over-year increase. In 2005 corporate costs of $3.3 million were charged to the segment. In 2006, 39 percent of operating expenses were recovered through cost flowthrough arrangements, as compared to 30 percent in 2005, consistent with the strategy to strengthen the financial returns in an increasing cost environment.

Amortization expense increased $2.9 million in 2006 over 2005 due to capital expenditures incurred in late 2005 and in 2006. In 2006 AltaGas recorded a write-down of goodwill of $0.6 million related to a non-core investment.

Operating income as a percentage of net revenue in the FG&P segment in 2006 was 20 percent in both 2006 and 2005. (See Non-GAAP Financial Measures section of this MD&A for description of operating income and net revenue.)

OUTLOOK

In 2006 North American natural gas markets experienced a softening of prices. As a result, many producers announced reduced drilling programs resulting in a decline in well tie-in activity in the latter half of the year. AltaGas expects the impact on throughput volumes to continue during this period of lower drilling and lower well tie-in activity. AltaGas expects its strategy to increase the percentage of operating costs flowed through to customers, additional volumes from its new facilities and take-or-pay contractual provisions will mitigate the impact of lower well tie-ins and natural declines.

In 2007 AltaGas expects there to be continued opportunities to expand, construct, and acquire processing facilities as producers continue to focus capital investment on drilling opportunities. AltaGas expects to spend approximately $50 million of capital on the construction of new, and the expansion of existing, FG&P facilities over the year.

BUSINESS STRATEGY AND OPPORTUNITIES

Field gathering and processing facilities are critical to the delivery of natural gas from the wellhead to the end-use market. AltaGas has grown its FG&P segment based on an acquisition and development strategy unique in the Canadian natural gas market. AltaGas' strategy is to:

- Expand its reach into British Columbia and northern Alberta where there is strong producer activity, less existing infrastructure and where existing producer processing facilities are fully utilized;
- Maintain flexibility by investing in moveable assets that can be easily and quickly redeployed to new locations, improving operational flexibility and profitability, and responding quickly to producer requirements;
- Offer customers diverse marketing opportunities by providing access to one or more downstream natural gas transportation pipelines;
- Acquire and maintain large working interests in assets to control operations, increase efficiency and maintain or enhance operational excellence and reduce operating costs;

80% of facilities are skid-mounted.

- Reduce overall business risk through geographic and customer diversity and contracting provisions, such as minimum volume commitments, to underpin expended capital;
- Acquire underutilized assets that offer upside through increased throughput;
- Build new facilities in response to producer demand in new exploration areas; and
- Construct or acquire and connect complementary facilities to create large facility complexes.

AltaGas seeks to increase the utilization of its facilities by:

- Increasing throughput by working closely with producers who are developing new and existing natural gas fields;
- Offering flexible contractual terms and equitable access to all producers in areas where AltaGas operates; and
- Enhancing operational efficiencies through consolidation and plant upgrades.

AltaGas complements its FG&P segment with investments in transmission pipelines and extraction plants and through its Energy Services business. AltaGas enhances the value of its gathering and processing infrastructure by providing a suite of integrated services such as natural gas transmission, NGL extraction and natural gas and NGL marketing to its customers.

AltaGas' FG&P segment is well positioned to take advantage of the existing and future gathering and processing needs of its customers. In addition to its network of approximately 6,000 km of gathering lines, substantial processing capacity, expansion potential and access to downstream transportation pipelines that offer customers diverse marketing opportunities, approximately 80 percent of the segment's compression units are skid-mounted. This allows AltaGas to move units quickly and cost-effectively to respond to the changing processing needs of its customers.

Existing field gathering and processing areas are generally surrounded by adjoining or overlapping gathering and processing systems. As AltaGas has grown, opportunities to expand by tying in new wells and building or purchasing adjoining facilities and systems have increased. New area development comes in large part from the drilling programs of AltaGas' existing and expanding customer base. At present, the majority of gathering and processing infrastructure in western Canada is still owned by oil and natural gas producers. AltaGas believes that its strong operational skills and extensive market penetration create opportunities to work with exploration and production companies to provide field gathering and processing services, in turn enabling producers to focus on exploration and production activities.

AltaGas maintains a conservative risk profile in part by focusing on acquisitions that create value for unitholders and refraining from transactions that it believes are overpriced and unlikely to be accretive to net income in the long term. Over the past few years, the midstream industry has experienced acquisition activity at prices with high earnings multiples for field gathering and processing assets. This has led AltaGas to focus primarily on building new facilities and expanding existing infrastructure, rather than on acquisitions. However, as a result of the softening of gas prices in 2006 and the slowdown in drilling that began in the second half of 2006, the opportunity may arise to acquire additional existing facilities as producers focus on drilling rather than on non-core activities, such as processing.

RISK MANAGEMENT

AltaGas' field gathering and processing facilities process or transport natural gas from the Western Canada Sedimentary Basin (WCSB). Throughput at these facilities is dependent on a number of factors including the level of exploration and development within the WCSB, the long-term supply and demand dynamics for natural gas which impacts the longer-term price of natural gas, and the regulatory environment for natural gas market participants. Consequently, AltaGas may be exposed to declining cash flows and profitability arising from reduced natural gas throughput as well as rising operating costs. AltaGas manages its exposure to financial risk in the FG&P segment using the strategies outlined below.

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Volume declines in the WCSB	• Contract provisions such as take-or-pay, capital cost recovery, area of mutual interest, geographic franchise with economic out, length of term and type of service, underpinned capital commitments.	• Many new contracts in 2006 included take-or-pay provisions. • $2.2 million in take-or-pay revenue in 2006. • 28 of 29 operating areas have area of mutual interest provisions.
	• AltaGas owns extensive gathering systems and moveable processing plants and can quickly deploy assets in response to customers' drilling activity and volume variability.	• Approximately 80 percent of compression units are skid-mounted. • In 2006, increased processing capability at 3 plants totalling 25 Mmcf/d, including Prairie River where up to 10 Mmcf/d was added using redeployed equipment.
	• Increase geographic and customer diversity to reduce exposure to any one customer or area of the WCSB.	• More than 260 customers with no customer representing more than 6 percent of FG&P net revenue during 2006. • Top 10 customers represented 13 percent of total consolidated net revenues in 2006. • 74 natural gas processing facilities in 29 operating areas in three provinces within the WCSB.
	• Expand into areas with strong producer activity and limited or fully utilized processing facilities.	• Acquired the new 10 Mmcf/d Clear Hills sour gas processing facility and an associated 16-kilometre sour gas gathering line in Northwest Alberta.
Increasing operating costs	• Contractual provisions provide recovery of actual operating costs. • Acquire large working interests to control and optimize operations, maximize efficiencies, customer demand and throughput.	• 76 percent of contracts have Alberta Consumer Price Index increases. • 39 percent of operating costs recovered in 2006 compared to 30 percent in 2005. • Average working interest of 92 percent. • Operate 71 of 74 FG&P facilities.
Natural gas price fluctuations	• Toll for service structure independent of commodity prices; revenues are a function of volumes processed.	• The majority of processing contracts are volumetric service fee structures, based on a rate per Mcf of throughput.
Environmental and safety	• AltaGas has strong safety and environmental management systems, which it continually strives to improve.	• Princess gas plant installed acid gas injection, reducing carbon dioxide and sulphur dioxide emissions to virtually zero. • Received Alberta Human Resources and Employment Work Safe Alberta 2005 Best Safety Award. Only 350 of Alberta's more than 128,000 employers received this award.

Stable, long-term contracts in place for majority of volumes.

The E&T segment consists of interests in four ethane and natural gas liquids extraction plants, five natural gas transmission systems and one condensate pipeline.

EXTRACTION

AltaGas owns extraction plant processing capacity through its interests in two extraction plants at Empress, Alberta, one extraction plant at Joffre, Alberta and one extraction plant in Edmonton, Alberta. AltaGas operates the Edmonton plant.

AltaGas' working interests in these extraction plants provide stable fixed-fee, cost-of-service type revenues and margin-based revenues. Also included in the extraction business is AltaGas' Bantry field fractionation facility. AltaGas' net raw gas licensed inlet capacity at these plants was 554 Mmcf/d at December 31, 2006. Fractionation services at Bantry are provided on a rate per cubic metre of product processed.

The value of ethane and NGL extraction is a function of the difference between the value of the ethane, propane, butane and pentanes-plus as separate marketable commodities and their value as constituents of the natural gas stream. This difference is commonly known as the frac spread. If the components are not extracted, they are sold as natural gas for their heating value at the prevailing natural gas price. As ethane and NGLs, the components are sold at higher prices that reflect the premium value of each of the individual commodities.

Extraction facility owners obtain the right to extract liquids from the natural gas stream, either directly as the owner of the gas, or through gas extraction agreements. The typical commercial arrangement involves the ethane and NGL extraction plant owner contracting with shippers on a gas transmission system for the right to extract the ethane and NGLs from the shipper's natural gas. By removing ethane and NGLs, the extraction plant is, in effect, extracting or shrinking a portion of the energy contained in the shipper's natural gas. The extraction plant owner pays the shipper for the extracted energy or alternatively replaces the extracted energy, thereby keeping the shipper whole. This purchased gas is referred to as shrinkage or make-up gas. Extraction contract terms may be for firm or interruptible processing, and may vary from monthly to multi-year in length. Currently the majority of AltaGas' extraction agreements are multi-year term arrangements.

The main business drivers in the extraction business are the volumes of ethane and NGLs produced which are impacted by contracted gas supply and the corresponding ethane and NGLs produced and the underlying financial terms of the contract in place.

TRANSMISSION

AltaGas owns five natural gas transmission systems and one condensate pipeline. The Suffield natural gas transmission system located in southeastern Alberta accounts for 75 percent of transmission net revenue and has capacity of 400 Mmcf/d. The majority of the Suffield system's capacity is currently contracted by EnCana through transport-or-pay and volume commitments that will expire in 2022 and be renewable for one-year periods thereafter. Volume commitments are expected to increase annually from approximately 360,000 GJ/d in 2006 to approximately 406,000 GJ/d in 2010 and will decline thereafter.

Other key pipelines are the AltaGas owned and operated Cold Lake natural gas transmission system which consists of 39 receipt

points and 36 delivery points (including four pipeline interconnects). The Porcupine Hills pipeline, located in southwest Alberta, is a single shipper condensate pipeline. The Porcupine contract, which expires on June 30, 2007, is expected to be extended on similar terms.

The transmission component's main business drivers are the fees earned which are based on contracted volumes and transmission capacity to serve new and expanding customer requirements for shipping gas to market.

RESULTS OF OPERATIONS

FINANCIAL RESULTS *($ millions)*	**2006**	2005
Revenue	**149.1**	181.3
Net revenue	**63.2**	58.0
Operating and administrative	**20.3**	20.1
Amortization	**7.7**	7.5
Operating income	**35.2**	30.4

OPERATING STATISTICS	**2006**	2005
Extraction inlet capacity (Mmcf/d)(1)	**554**	539
Extraction volumes (Bbls/d)(2)	**19,696**	19,357
Transmission volumes (Mmcf/d)(2)(3)	**400**	432

(1) As at December 31.

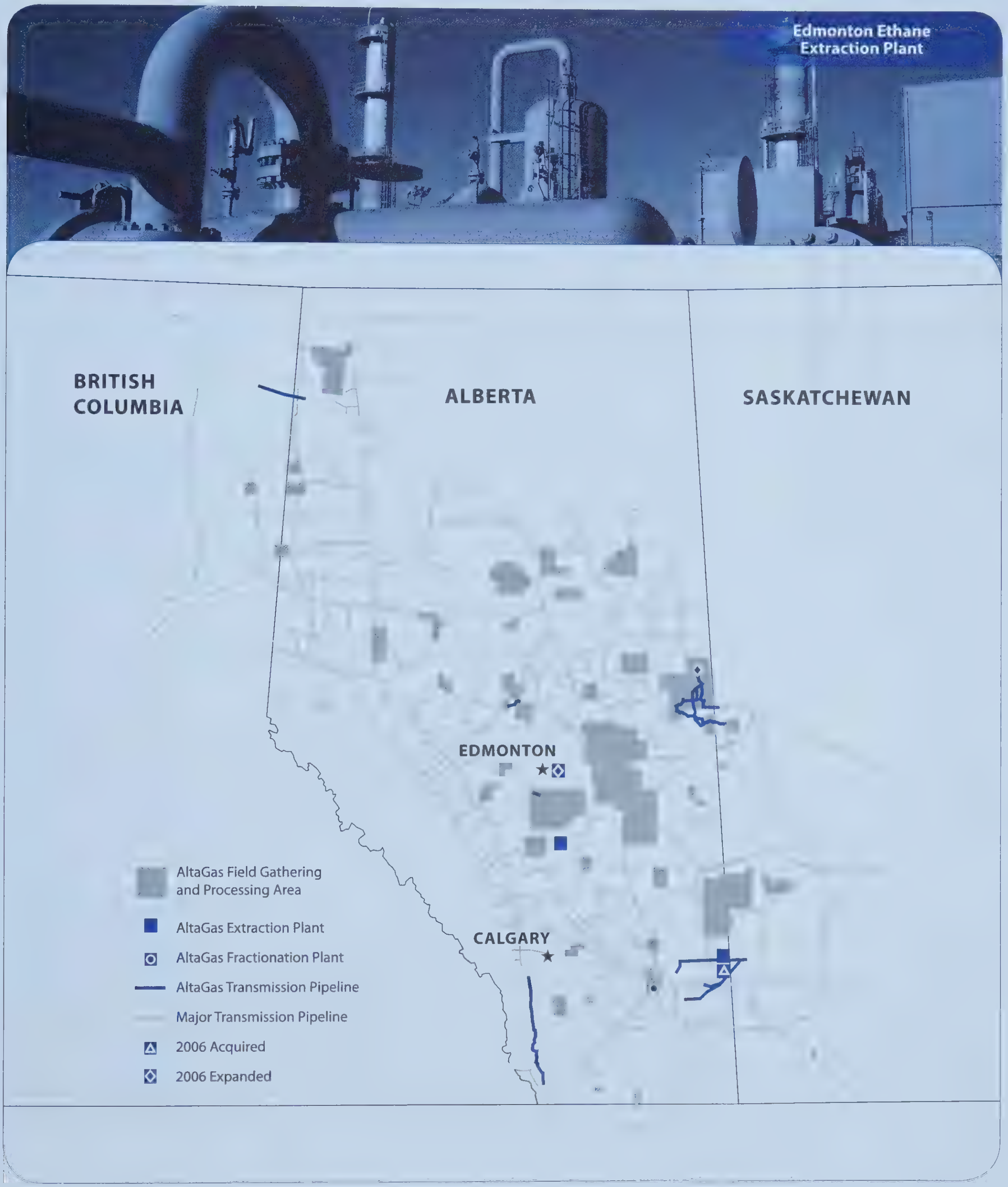
(2) Average for the period.

(3) Excludes condensate pipeline volumes.

Operating income in the E&T segment in 2006 was $35.2 million compared to $30.4 million in 2005. The increase was mainly due to higher NGL frac spreads and higher volumes processed in the extraction business. Approximately 93 percent of AltaGas' total extraction volumes in 2006 were processed under long-term, fixed-fee or cost-of-service arrangements compared to 95 percent in 2005. The remaining volumes were subject to NGL frac spreads, allowing AltaGas to benefit from the historically high NGL frac spreads of approximately $18.50/Bbl in 2006 compared to approximately $9.50/Bbl in 2005. The percentage of total extraction volumes exposed to frac spreads increased slightly in 2006 as a result of higher utilization of the facilities compared to 2005 resulting in the incremental NGLs being sold at market prices. Over the past four years AltaGas realized average frac spreads of approximately $10/Bbl.

In the transmission business, pipeline throughput has minimal overall impact on the financial results due to cost-of-service and take-or-pay contractual arrangements in place. On the Suffield system, the major shipper pays AltaGas based on a daily contract quantity (DCQ). When annual volumes shipped are less than the annualized daily contract quantity (shortfall volumes), there is no refund paid to the shipper and AltaGas posts the shortfall quantity to a shortfall account as a credit. With respect to any year where a shipper's quantity exceeds the DCQ, and to the extent there is a shortfall account, the shipper may apply excess quantities up to an amount equal to 10 percent of the annualized DCQ to reduce any shortfall account balance. Shortfall amounts expire five years following the year in which they are created and AltaGas incurs no additional cost on draw-down of the shortfall account. In 2006 AltaGas deferred $0.8 million of revenue to account for the obligation outstanding under this arrangement. In 2005 no revenue was deferred as the shipper transported more than the minimum annualized DCQ. Based on current and expected volumes on the Suffield system AltaGas expects this deferral to be reversed by 2011.

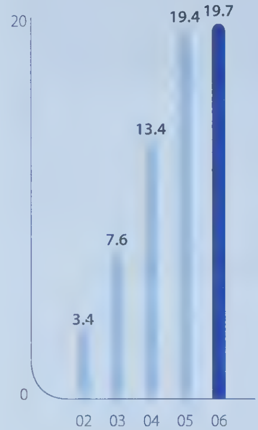
In 2006 transmission volumes declined to 400 Mmcf/d from 432 Mmcf/d due to lower deliveries from shippers, primarily on the Suffield and Cold Lake transmission systems. As a result, operating income in the transmission business decreased in 2006 due



to the deferral of $0.8 million related to shortfall volumes credited to a shipper's account in the year. Overall AltaGas volumes are transported through cost-of-service or take-or-pay arrangements which provide a stable source of income.

Average ethane and NGL volumes increased to 19,696 Bbls/d in 2006 from 19,357 Bbls/d in 2005. Volumes increased mainly due to the full-year impact of operating in higher ethane recovery mode at one of the Empress extraction facilities and due to higher natural gas volumes processed at the Empress facilities in collaboration with the Energy Services segment.

EXTRACTION PRODUCTION
Million Bbls/d



Revenue in the E&T segment in 2006 was $149.1 million compared to $181.3 million in 2005. The decrease was mainly due to purchasing arrangements associated with the replacement of shrinkage gas in the extraction business in 2005.

In 2006 net revenue was $63.2 million compared to $58.0 million in 2005, mainly due to higher NGL frac spreads throughout the year and higher extraction volumes in the last half of the year. Higher NGL frac spreads contributed $3.7 million, higher ethane and NGL volumes in the last half of the year contributed $3.3 million and higher recovery of operating costs contributed $0.7 million to the increase for 2006. The increases in net revenue associated with the extraction business were partially offset by lower revenues in the transmission business as a result of the volume shortfall on the Suffield system and lower cost recoveries.

Operating and administrative expense in the E&T segment in 2006 was $20.3 million compared to $20.1 million in 2005. The increase was primarily due to higher operating costs in extraction which were recovered, along with higher administrative expenses. The increases were partially offset by lower operating costs in the transmission business in 2006 compared to 2005, when operating expenses were higher due to weather-related damage on the Porcupine Hills pipeline which were recovered from the shipper, and due to higher National Energy Board costs incurred.

Amortization expense in the E&T segment in 2006 was relatively flat at $7.7 million compared to $7.5 million in 2005.

Operating income as a percentage of net revenue in the E&T segment in 2006 was 56 percent compared to 52 percent in 2005. The increase was mainly due to higher NGL frac spreads and higher volumes processed in the extraction business. (See Non-GAAP Financial Measures section of this MD&A for description of operating income and net revenue.)

OUTLOOK

The E&T segment is expected to continue to deliver strong performance and predictable and stable returns due to contractual arrangements in place. In the extraction business, the enhanced ethane recovery project at EEEP was completed in January 2007 and increased ethane production capability by 800 Bbls/d. The full-year production impact of the enhanced ethane recovery project and increased ownership of one of the Empress facilities are expected to contribute to earnings starting in the first quarter of 2007. In 2007 NGL frac spreads are expected to decline to a level closer to the historical average, based on current natural gas and product price forecasts. However, any impact from lower frac spreads is anticipated to be mitigated by the increased utilization at the Empress facilities.

In the transmission business, results are expected to be slightly higher than in 2006 as AltaGas does not expect revenue to be deferred given current transmission volumes on the Suffield system. Should annual volumes be lower than the annualized DCQ, AltaGas will defer the revenue until such time as the shortfall account is drawn down or the time to draw down the shortfall expires. The Cold Lake pipeline expansion is expected to be completed by May 1, 2007 and is expected to positively impact earnings upon startup.

BUSINESS STRATEGY AND OPPORTUNITIES

AltaGas' strategy in the E&T segment is to:

- Maintain stable cash flow by using commercial arrangements that have long-term, fixed-fee or cost-of-service provisions with volume commitments from producers;
- Increase extraction plant and transmission system utilization and expand existing facilities;
- Acquire and develop new facilities or increase working interest ownership of partially owned facilities; and
- Leverage the extraction and transmission infrastructure by offering and bundling marketing, transportation management and processing services in collaboration with the Energy Services and FG&P segments.

The main business drivers in the extraction business are the volume of ethane and NGL produced which is impacted by the volume of natural gas processed, natural gas composition, recovery efficiency of the extraction plant and plant online time. Extraction growth opportunities may arise from: plant modifications to increase product recoveries at facilities in which AltaGas already has ownership interests; increasing interests in existing extraction plants; the construction of new facilities; and increased throughput due to additional extraction agreements. Extraction plant opportunities typically reflect lower-risk, long-term, cost-of-service ethane processing arrangements contracted with Alberta ethylene producers; lower-risk, long-term NGL fixed-processing-fee arrangements; and a small percentage of short-term sales of NGL based on an Edmonton or U.S. index.

The transmission component's main business drivers are the fees earned which are based on contracted volumes and transmission capacity to serve new and expanding customer requirements for shipping gas to market. Due to the integrated nature of AltaGas' businesses, transmission services are often offered in combination with AltaGas' gathering and processing, natural gas marketing and extraction services. AltaGas works with customers to create transmission solutions in areas where there is no or limited pipeline capacity. In capturing opportunities, AltaGas focuses on long-term, cost-of-service type contractual arrangements.

RISK MANAGEMENT

AltaGas' extraction facilities and transmission assets process or transport natural gas and condensate from the WCSB. Utilization of these facilities is dependent on a number of factors including natural gas supply, the ability of natural gas producers to deliver natural gas to the various pipeline systems and processing facilities, the longer-term price of natural gas, the level of demand for ethane and NGLs and the regulatory environment for natural gas market participants. The extraction component is further influenced by natural gas composition and the difference between the value of the ethane, propane, butane and pentanes-plus as separate marketable commodities and their value as constituents of the natural gas stream. AltaGas manages its exposure to financial risk in the E&T segment using the strategies outlined on the following page.

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Long-term decline in throughput and gas composition variability	• Contract provisions underpin capital commitments. • Long-term contracts independent of throughput. • Collaborate with Energy Services segment to increase volumes through the extraction facilities.	• Majority of contracts are multi-year. • 75 percent of NGL production under long-term, fixed-fee arrangements. • Ethane production sold under long-term, cost-of-service or fixed-fee contracts. • In 2006 volume was 30 Mmcf/d higher at one of the Empress extraction facilities as a result of natural gas supply arranged by the Energy Services segment. • 96 percent of transmission contracts are cost-of-service or take-or-pay.
	• Implement plant modifications to increase product recoveries and increase utilization.	• Commenced the $2.2 million project to increase processing capacity and ethane recovery at the Edmonton extraction plant. The changes are expected to increase ethane production at the plant by almost 10 percent on an annualized basis, adding 800 Bbls/d of ethane.
	• Expand existing facilities or acquire or construct new facilities.	• Announced the expansion of the Cold Lake natural gas transmission system by 18 Mmcf/d to serve BlackRock Ventures Inc., a subsidiary of Shell Canada.
Commodity price fluctuations	• Contracting terms and processing fees independent of commodity prices with fee-for-service or cost-of-service provisions.	• 75 percent of NGL production under long-term, fixed-fee arrangements. • Only 7 percent of total extraction production was exposed to frac spreads in 2006. • Ethane production sold under long-term, cost-of-service or fixed-fee contracts. • If uneconomical to produce, NGL is reinjected or extraction operations are reduced or suspended. • The transmission business is not affected by commodity price fluctuations.
Increasing operating costs	• Acquire large working interests to control and optimize operations and maximize efficiencies. • Structure fees to recover actual operating costs.	• Significant portion of cost-of-service contracts provide for operating cost recovery. • Some extraction contracts allow recovery of certain operating costs, including shrinkage gas attributable to that production.
Environmental and safety	• AltaGas has strong safety and environmental management systems, which it continually strives to improve.	• The Cold Lake expansion route minimizes environmental impact in a highly sensitive and historical area.

POWER GENERATION

87% increase in operating income.

AltaGas has 378 megawatt (MW) of total power generation capacity in Alberta through a 50 percent ownership interest in the Sundance B PPAs and a capital lease for 25 MW of gas-fired power peaking capacity.

AltaGas' 378 MW of power capacity served approximately 5 percent of Alberta's power demand at December 31, 2006. The Power Generation segment is primarily engaged in the sale of electricity and ancillary services to the Alberta wholesale market from the dispatch and sale of power from the coal-fired Sundance plant and gas-fired peaking capacity.

PPAs were established in 1999 under Alberta's program of power industry deregulation. PPAs were created to separate ownership of the physical power generation assets from control of output. The 50 percent interest in the Sundance B PPAs provides AltaGas with the rights to a specified target level of 86 percent of the Sundance B plants' rated capacity, as well as to ancillary services until December 31, 2020.

Results in the Power Generation segment are largely driven by target availability, hedge prices (for the portion of capacity that is hedged) and Alberta spot prices (for the portion of capacity that is not hedged). The interrelationship of production, spot prices and cost of sales is specified in the PPA. Generally, AltaGas is compensated when power production is less than target levels, at a rate based on the previous 30-day average spot price (RAPP). Similarly, if generation from the PPAs is above target, AltaGas is obligated to provide the owner of the generation facility, TransAlta Corporation (TransAlta), financial compensation based on the difference between actual availability and target availability, multiplied by RAPP. The financial exposure may be positive or negative depending on the difference between the current Alberta spot price and RAPP. The majority of the cost of sales is the fixed costs and variable operating costs paid to TransAlta and the variable costs of transmission and Alberta Power Pool trading charges.

The gas-fired generation was acquired under a capital lease with a 10-year term that commenced September 1, 2004 and includes an option at the end of the initial term to extend the term for 15 years or to purchase the assets. The capital lease requires AltaGas to pay a monthly variable operating and maintenance charge plus a capacity fee. The Energy Services segment manages the gas requirement and the units are dispatched from the control centre at EEEP. This 25 MW of gas-fired power capacity provides fuel diversity to AltaGas' power business and provides partial backstopping to outages at Sundance. In addition, due to their quick ramp-up capability, the peaking plants provide revenue from the sale of energy and ancillary services.

The main business drivers in the Power Generation segment are the prices at which power sales are hedged, spot prices received on the unhedged portion of the power portfolio, the amount of power generated from the Sundance plant, and AltaGas' ability to maximize earnings through the sale of power and ancillary services from the gas-fired peaking facility.

RESULTS OF OPERATIONS

FINANCIAL RESULTS *($ millions)*	2006	2005
Revenue	**199.4**	189.2
Net revenue	**99.6**	57.8
Operating and administrative	**1.3**	1.8
Amortization	**7.4**	7.3
Operating income	**90.9**	48.7

OPERATING STATISTICS	2006	2005
Volume of power sold (GWh)	**2,878**	3,466
Average price received on the sale of power ($/MWh)(1)	**69.26**	54.59
Alberta Power Pool average spot price ($/MWh)(1)	**80.48**	70.19

(1) Average for the period.

In 2006 operating income for the Power Generation segment was $90.9 million, almost double 2005 operating income of $48.7 million. The increase was due to higher power prices, lower power transmission charges and higher earnings from the gas-fired peaking plants, partially offset by the expiration of the Genesee power contract at the end of first quarter 2006.

Net revenue in 2006 was $99.6 million compared to $57.8 million in 2005, an increase of $41.8 million. The increase was due to higher average power prices received on hedged and unhedged power volumes related to the Sundance PPAs ($23.8 million). The increase in net revenue was also due to lower transmission costs ($18.4 million) related to changes in interconnection charges and lower line losses due to lower system loss rates and lower generation. Effective January 1, 2006 the responsibility for interconnection and operating reserve charges was shifted to power purchasers from power generators.

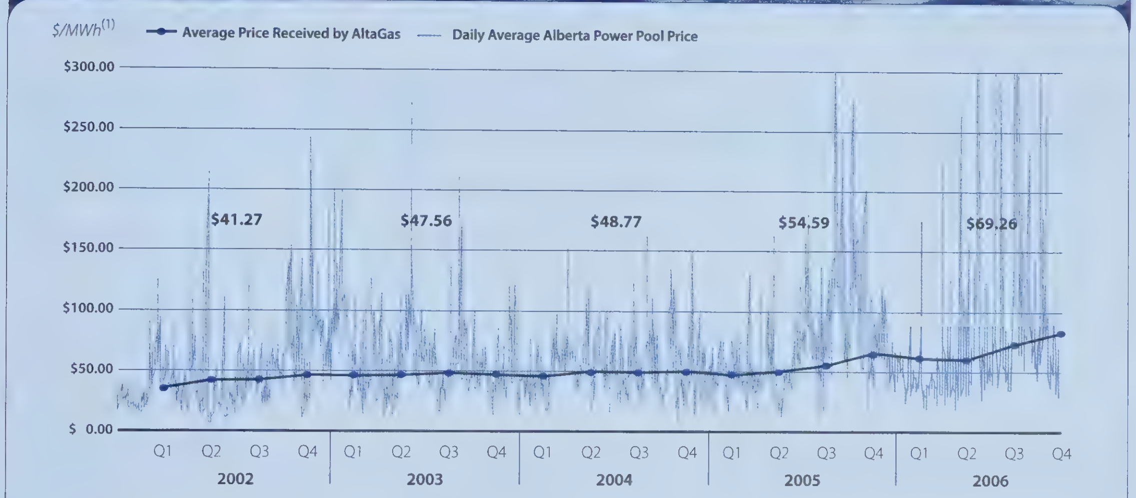
The gas-fired peaking plants also benefited from the strong Alberta power market in 2006, contributing $2.1 million to the increase in net revenue in 2006 compared to 2005. The increases were partially offset by the expiration of the Genesee power contract on March 31, 2006 which contributed approximately $6.5 million to net revenue in 2005 versus $4.0 million in 2006.

Operating and administrative expense in 2006 were slightly lower than in 2005 due to corporate costs of $0.4 million allocated to the segment in 2005.

Amortization expense in 2006 was similar to 2005 as capital assets employed in the segment were the same in 2006 as in 2005.

Operating income as a percentage of net revenue increased to 91 percent in 2006 from 84 percent in 2005. The increase was primarily due to higher power prices and lower transmission costs. (See Non-GAAP Financial Measures section of this MD&A for description of operating income and net revenue.)

Volume of power sold in 2006 was lower than in 2005 as a result of the expiration of the Genesee power contract on March 31, 2006.



(1) Chart truncated at $300.00; daily average Alberta power pool price reached as high as $999.99/MWh.

OUTLOOK

Operating income from hedged power volumes in 2007 is expected to be higher than in 2006. Consistent with AltaGas' hedge program, approximately two-thirds of the power available from the Sundance B PPAs has been hedged, with the remaining one-third exposed to the spot market price of power in Alberta. The price at which volumes have been hedged is higher than in the prior year. The volumes from the Sundance PPAs exposed to spot prices in 2007 remain approximately the same as in 2006, but due to the expiration of the Genesee contract in March 2006, overall volumes exposed to spot prices will be lower.

In Alberta natural gas prices influence the price of power. While the Alberta economy has been strong and there has been strong power demand growth and marginal additions to supply, power prices could potentially be lower than those observed in 2006 if natural gas prices are lower in 2007.

During 2006 AltaGas announced it had entered into partnerships with two developers, Aeolis and GreenWing, to develop and own wind power projects as part of its strategy to expand ownership of power generation assets, particularly renewable generating capacity.

The Bear Mountain Wind project, which is being developed with Aeolis, has a 25-year electricity purchase agreement with BC Hydro, and a planned in-service date of late 2009. AltaGas and Aeolis are continuing to optimize the project configuration and finalize key supplier contracts and expect to commence construction in 2007. As the project is likely to include one or more additional investors, AltaGas has not yet finalized its ownership interest in the project.

AltaGas has invested $4.3 million in the development of wind projects, and has issued a letter of credit for $7.2 million relating to the Bear Mountain Wind project. AltaGas continues to work with its partners to develop projects in a number of other jurisdictions. The projects currently under development are expected to generate earnings commencing in 2009 and beyond.

Approximately 2/3 of power production is hedged, balancing price and operational risk.

BUSINESS STRATEGY AND OPPORTUNITIES

AltaGas' Power Generation strategy is to:

- Optimize existing power investments and invest in power opportunities such as additional PPAs in Alberta and other provinces;
- Develop power generation projects supported by long-term power sales arrangements;
- Diversify geographically and by fuel source;
- Capitalize on increasing demand for clean power across Canada and the northern U.S. by investing in renewable power project development;
- Develop operational capability;
- Drive stable, predictable cash flow from long-term contracts with investment-grade counterparties; and
- Capitalize on internal synergies by providing power to the FG&P, E&T and Energy Services segments.

The supply-demand fundamentals supporting the Power Generation segment are favourable. Energy demand continues to grow in Alberta and natural gas prices are expected to remain strong over the longer term, which is expected to support strong power prices. This could increase the profitability of AltaGas' base-load, coal-fired PPAs while allowing it to earn higher revenues from the sale of ancillary services from its coal and gas-fired peaking capacity. The expectation of continued strong power prices is further supported by the tightening of the electricity reserve margin in Alberta as transmission constraints are dampening the construction starts of new generation facilities.

Power Generation development and ownership opportunities are likely to arise as a function of the growing North American demand for cleaner energy sources such as natural gas, hydro and wind. The decommissioning of thermal plants in Ontario, and beginning in 2010 in Alberta, may present additional growth opportunities through the development and ownership of new capacity. In addition, the sale of contractual rights to existing generation capacity by provincial systems operators may provide further growth prospects.

RISK MANAGEMENT

The main risks faced in the power business are power prices, the cost of power, the volume of power generated, counterparty risk and regulatory risk related to the deregulation of power and the environment. Power revenues are generally driven by volumes of power generated, power prices and the cost of power. Power prices are impacted by fluctuations in supply and demand as a consequence of weather, customer usage, economic activity and economic growth; the cost of power is driven by operating costs, changes in transmission rates, and reductions in power available for sale, mainly due to outage and force majeure events. AltaGas mitigates these risks through the strategies outlined in the following table.

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Power price volatility	• A disciplined hedging strategy – hedge targets approved by the Board of Directors. • Hedge transactions monitored by the Risk Management Committee. • In-depth Alberta power market knowledge and experience. • Hedges own electrical demand requirements.	• Financial hedge contracts generally have terms ranging from three to 36 months. • Average sales price received in 2006 was \$69.26/MWh, compared to average monthly Pool price which ranged from a low of \$42.36/MWh in April to a high of \$174.09/MWh in October. • Supply 11 MW for own use and supply approximately 10 MW to Alberta power retail customers.
Volume of power generation	• PPAs set specified target availability levels. TransAlta is obligated to provide AltaGas financial compensation to the specified target availability level (86 percent of rated capacity in 2006). • Diversification of fuel sources and geography. • Hedging strategy balances price and operating risk. • Partner with developers with expertise in alternative fuel sources.	• No material negative impact on revenue despite lower power generation from the facility due to prolonged planned outage in 2006. • 25 MW of gas-fired generation provided partial operational backstopping to the Sundance PPAs and contributed higher earnings in 2006. • Short-term power purchase contracts used to mitigate the impact of a prolonged planned outage in 2006. • Wind power projects under development outside Alberta.
Cost of power	• Cost of power from the coal-fired generation based on PPA indices.	• Modest increase in cost of power from Sundance PPAs in 2006.
Counterparty risk	• Strong credit policies. • Exposures and impact of price shocks on liquidity are closely monitored.	• All financial hedge counterparties are investment-grade. • No counterparty defaults in 2006.
Regulatory risk	• Regulatory and commercial personnel work closely to monitor and react to regulatory issues. • The PPAs have provisions for financial relief in the event that policies and regulations make the PPAs uneconomic.	• Monitored developments on the regulatory and environmental landscape and participated in industry committees. • AltaGas personnel hold influential positions on key industry policy and oversight committees.

ENERGY SERVICES

Integrated with AltaGas' asset-based segments.

The Energy Services segment consists of two main components: an energy management business providing energy consulting and supply management services and arranging gas and power supply for non-residential end-users; and a gas services business buying and reselling natural gas, transportation and storage. The segment also includes a small portfolio of oil and natural gas production.

The Energy Services segment is interconnected with AltaGas' asset-based segments. The gas services group contracts supply and shrinkage gas for AltaGas extraction facilities. It also contracts and resells capacity on AltaGas transmission pipelines, providing gas control services to balance gas flows. Gas services markets gas for FG&P customers and in the process earns margins, manages credit exposure and provides additional value-added services to AltaGas' producer customers. In addition, it contracts and manages gas for AltaGas' peaking plants. In Alberta, AltaGas' energy management business manages electricity supplies for AltaGas' internal power demand in the FG&P and E&T segments and sells power to retail customers from the Power Generation segment.

The Energy Services segment identifies opportunities to exchange, reallocate or resell pipeline capacity and storage to earn a profit. Net revenues from these activities are derived from low-risk opportunities based on transportation cost differentials between pipeline systems. Margins are earned by simultaneously locking in buy and sell transactions and managing credit exposures.

ENERGY MANAGEMENT

The energy management business consists of arranging natural gas and power supply and related transportation contracts and providing energy consulting services for commercial, industrial, agricultural, and institutional end-users across Canada. As of January 1, 2007 AltaGas' energy management services are provided under the brand name ECNG Energy and are supported by employees in Burlington and Chatham, Ontario; Calgary, Alberta; and Burnaby, British Columbia.

The majority of this fee-for-service business is based on one to three-year evergreen contracts, with some extending as far as eight years. Fees are earned by providing advisory services, and arranging and managing supply on behalf of customers. These services allow customers to reduce exposure to gas and power price volatility and to match their energy supply arrangements with their risk and budget objectives.

In the energy management business, AltaGas mainly enters into agency retainer agreements with clients, under which it provides gas and electricity supply and price management advice to its customers. Under these agency agreements AltaGas, on behalf of its end-use customers, also purchases and manages gas supply and fixes the price of customer electricity purchases. AltaGas acts as agent on behalf of its customers and is generally not exposed to changes in commodity prices.

GAS SERVICES

Energy Services includes a gas services business, focused on buying and reselling gas transportation and storage, and marketing natural gas for producers. Within the gas services business, AltaGas takes ownership of the gas and earns a fixed margin. The gas supply comes from both deliveries of natural gas processed at AltaGas' facilities and from deliveries not associated with AltaGas' facilities. Purchase and sales transactions are matched back-to-back to lock in a margin at the time the sale is made.

AltaGas also provides energy procurement services for a select group of industrial and other users including AltaGas Utilities Inc.,

wholly owned by AltaGas Utility Group Inc., the publicly traded entity created from the spin-out of the Natural Gas Distribution segment in 2005. Similar gas supply management arrangements are in place with other industrial and producer customers, including the Joffre ethane extraction plant. In addition, AltaGas manages the third-party pipeline transportation requirements for many of its gas marketing customers.

In addition to its commodity purchase and sale business, AltaGas' gas services business includes transportation arrangements into eastern Canadian markets and within Alberta in the form of gas exchange arrangements with AltaGas' gathering and processing customers. AltaGas markets or exchanges all of the volumes that flow through its Cold Lake and Summerdale pipeline systems. In a gas exchange transaction AltaGas receives natural gas from customers on an AltaGas system and delivers the gas to its customers on the TransCanada, ATCO or TransGas systems. By purchasing or exchanging gas on these pipeline systems and at other facilities, AltaGas has been successful in achieving positive margins while providing improved netbacks for producers.

OIL AND GAS PRODUCTION

Over the past several years, AltaGas has accumulated a portfolio of oil and natural gas production assets in connection with larger acquisitions of gathering and processing facilities. The portfolio is non-core to the operations. AltaGas is not in the business of exploration and development of natural gas reserves, as it chooses not to compete with producers flowing natural gas through its gathering and processing systems. AltaGas held and produced these assets primarily as a hedge to a long-term natural gas sales contract. Late in 2006 the Trust fixed the price for this long-term natural gas commitment with a third party. Production from these producing assets is sold on the spot market.

The main business drivers in the Energy Services segment are margins earned on volumes bought, sold and exchanged, fees earned on energy advisory services, production in the oil and gas production business and the spot price of natural gas and oil.

RESULTS OF OPERATIONS

FINANCIAL RESULTS *($ millions)*	**2006**	2005
Revenue	**948.9**	1,080.2
Net revenue	**24.7**	23.5
Operating and administrative	**17.1**	14.8
Amortization	**4.8**	3.1
Operating income	**2.8**	5.6

OPERATING STATISTICS	**2006**	2005
Energy management service contracts(1)	**1,394**	1,243
Average wholesale volumes marketed (GJ/d)(2)	**327,057**	312,272

(1) Active energy management service contracts at the end of the reporting period.

(2) Average for the period.

Operating income in the Energy Services segment in 2006 was $2.8 million compared to $5.6 million in 2005. The decrease was primarily due to lower production volumes and higher depletion rates in oil and gas production, higher amortization related to energy services contracts and relationships, and general cost escalations. The decreases were partially offset by growth in the fixed margins received from back-to-back buy and sell gas contracts and higher advisory services fees.

Net revenue for the Energy Services segment in 2006 was $24.7 million compared to $23.5 million in 2005. The increase was due to the acquisition of the iQ2 business in fourth quarter 2005 ($2.2 million), additional back-to-back buy and sell gas contracts ($1.0 million), and growth in advisory services fees through the addition of new energy management customers in Ontario ($0.7 million), partially offset by lower production volumes in oil and gas production ($1.6 million) and lower transportation and

exchange margins in the gas services business. Net revenue in 2005 also included a settlement of $0.6 million related to a gas marketing contract.

Operating and administrative expense in 2006 was $17.1 million compared to $14.8 million in 2005. The increase was primarily due to the acquisition of the Alberta energy management business in November 2005 ($1.6 million) and higher general and administrative costs.

Amortization expense in 2006 was $4.8 million compared to $3.1 million in 2005. The increase was due to $1.1 million higher amortization related to energy services contracts and relationships and $0.6 million higher depletion and depreciation rates in the oil and gas production business.

Operating income as a percentage of net revenue in 2006 was 11 percent compared to 24 percent in 2005. The decrease was primarily due to a lower contribution from the oil and gas production business, higher operating and administrative costs and higher amortization. (See Non-GAAP Financial Measures section of this MD&A for description of operating income and net revenue.)

OUTLOOK

The core businesses within the Energy Services segment are the advisory fee-based business serving non-residential gas and electricity end-users (energy management), and the fixed-margin gas marketing business (gas services). In 2007 growth in energy management fees is expected from the addition of agency service customers due to the recent expansion into electricity supply management in Ontario and from a focused national account strategy. The gas services component is also expected to grow as a result of locking in back-to-back buy and sell gas contracts which are expected to produce fixed margins for terms of up to five years.

The Energy Services segment is also an important element in increasing the value of assets in AltaGas' other segments. Energy Services connects and interacts with the other segments and in this capacity is expected to contribute to earnings growth across AltaGas.

The oil and gas production business is not a core business, and is experiencing production declines as a result of minimal capital expenditures in 2006. The underlying reserves continue to have value. AltaGas is considering alternatives for maximizing the value of these assets.

BUSINESS STRATEGY AND OPPORTUNITIES

AltaGas' Energy Services business strategy is to:

- Capitalize on market knowledge, expertise and customer relationships to grow the gas services business;
- Grow organically by building on recent acquisitions and national brand development;
- Maintain high renewal rates of energy management contracts;
- Increase market penetration of national energy management services in natural gas and electricity;
- Add physical infrastructure such as gas storage capacity; and
- Strengthen the integration of the FG&P, E&T and Power Generation segments – pursue opportunities to market natural gas for producers; sell natural gas, transportation and storage services to bring more volumes through AltaGas' facilities. These synergies would generate new sources of revenue to enhance AltaGas' earnings.

In the Energy Services segment, AltaGas expects continued organic growth through the addition of energy management customers as well as through expansion of services to existing customers by managing both gas and electricity supply nationwide. Customer demand for energy management and advisory services continues to grow as a result of energy price volatility. AltaGas continues to capitalize on the interconnection across segments, including using marketing and contracting expertise of the gas services group to generate earnings from AltaGas' assets. This intersegment potential includes increasing services on AltaGas transmission assets as well as identifying and capitalizing on market opportunities in collaboration with other operating segments.

RISK MANAGEMENT

In the energy management business, AltaGas competes with other marketing and consulting firms. In the gas services business, AltaGas' competitors range from owner-managed operations to large marketing and aggregation companies, the marketing arms of the large oil and gas producers, as well as a limited number of energy utilities. The most significant risks in the Energy Services segment are counterparty and commodity price risk. The credit-intensive nature of this business requires a strong balance sheet to support fixed-price energy purchase and sale agreements. AltaGas' strategies for mitigating the risks associated with this business are outlined in the following table.

Risks	Strategies and Organizational Capability to Mitigate Risks	Indicators and Achievements
Counterparty risk	• Strong credit policies. • Internal credit ratings and thresholds established. • Exposures and impact of price shocks on liquidity are closely monitored. • Diverse customer and supplier base. • The business model in energy management is based on agency arrangements.	• Majority of counterparties are investment-grade. • In energy management business, customers are aggregated into groups with joint and several liability for payment. • No Energy Services customer represented more than 5 percent of consolidated revenues during 2006. • In 2006 AltaGas added customers in key sectors nationwide. • Purchased natural gas from a wide array of investment-grade suppliers. • There have been no losses due to counterparty defaults in 2006.
Commodity price risk	• Commodity Risk Policy prohibits transactions for speculative purposes. • Strong systems and processes for monitoring and reporting compliance with Commodity Risk Policy. • In-depth knowledge of transportation systems and natural gas markets. • Strong customer relationships.	• All positions are back-to-back with locked-in margins. • Energy management contracts with terms from one to eight years with locked-in margins and fees. • Advisory fee services business experienced renewal rate of 95 percent in 2006. • Market and manage FG&P customers' gas for fee. • In majority of energy management business AltaGas acts as agent, taking no direct commodity price risk.

NATURAL GAS DISTRIBUTION

The NGD segment included AltaGas Utilities Inc., AltaGas' one-third interest in Inuvik Gas Ltd. and its 24.9 percent interest in Heritage Gas Limited. On November 17, 2005, the Trust spun out its NGD business into a separate, publicly traded entity, AltaGas Utility Group Inc. (Utility Group).

FINANCIAL RESULTS *($ millions)*	**2006**	2005[1]
Revenue	–	113.4
Net revenue	–	29.0
Operating and administrative	–	16.0
Amortization	–	6.8
Operating income (loss)	–	6.2

(1) For the period January 1 to November 17.

Through a series of transactions, the Trust's ownership interest in Utility Group, the holding company of the former NGD segment, was reduced to 26.7 percent on November 17, 2005. Prior to these transactions, the operations and financial results of the NGD segment were consolidated by the Trust. Beginning November 17, 2005, the Trust accounts for its ownership interest in Utility Group as an equity investment, recognizing its share of net income or loss in the Corporate segment using the equity method of accounting.

CORPORATE

The Corporate segment includes the cost of providing corporate services and general corporate overhead and investments in public and private entities.

FINANCIAL RESULTS *($ millions)*	**2006**	2005
Revenue	**4.4**	10.9
Net revenue[1]	**4.4**	10.9
Operating and administrative	**29.7**	15.8
Amortization	**2.3**	2.0
Operating loss[1]	**(27.6)**	(6.9)

(1) Non-GAAP financial measure. See discussion in Non-GAAP Financial Measures section of this MD&A.

RESULTS OF OPERATIONS

The operating loss for the segment increased to $27.6 million in 2006 from $6.9 million in 2005. The increase was primarily due to gains related to AltaGas' interest in Taylor NGL Limited Partnership reported in 2005, higher compensation and administrative costs, corporate costs charged to the operating segments in 2005 and increased costs incurred to meet new certification requirements for reporting issuers by the Canadian Securities Administrators. These increases were partially offset by higher equity earnings reported from AltaGas' investment in Utility Group for all of 2006 compared to six weeks in 2005, higher earnings from the investment in Taylor and a write-down of an investment in a private company in fourth quarter 2005.

Revenue for the year was $4.4 million compared to $10.9 million in 2005. The decrease was due to higher earnings from the Taylor and Utility Group investments ($3.0 million), which were more than offset by the $8.6 million one-time contributions related to the Trust's ownership of Taylor units, the gain of $0.9 million reported on the spin-out of the NGD segment and a write-down of $0.6 million on an investment in the shares of a private company reported in 2005.

Operating and administrative expense for 2006 was $29.7 million, compared to $15.8 million in 2005. The increase was due to higher salaries and benefits ($7.0 million), overall general increases of $1.4 million, higher technology support costs of $0.6 million and $1.0 million higher costs incurred to meet new certification requirements for reporting issuers. In 2005 $3.9 million of corporate costs were allocated to the operating segments.

Amortization expense was $2.3 million in 2006 compared to $2.0 million in 2005. This increase was due to increased administrative capital costs, including computer hardware and software projects to support the growth of the Trust.

OUTLOOK

In the Corporate segment, the operating loss is expected to be slightly lower than in 2006 as revenues from the investments in Taylor and Utility Group are expected to stay relatively flat compared to 2006 and AltaGas expects lower operating and administrative expense due to lower ongoing costs to meet the certification requirements mandated by the Canadian Securities Administrators.

INVESTED CAPITAL

During 2006 AltaGas acquired $71.5 million in capital assets, long-term investments and other assets, compared to $90.2 million in 2005. Growth capital of $62.0 million included the Blair Creek, Clear Prairie, Prairie River, Princess and Clear Hills gas plants, and an increased ownership interest in the Pouce Coupe facility in the FG&P segment. In the E&T segment growth capital included the ethane enhancement recovery project at EEEP and the increased interest at one of the Empress facilities. In the Power Generation segment $4.3 million was spent developing wind power projects through partnerships with wind developers.

Maintenance capital projects totalling $6.1 million in 2006 (2005 – $8.0 million) were undertaken mainly in the FG&P segment. An additional $3.4 million (2005 – $4.1 million) was spent in 2006 on administrative capital, including computer hardware and software projects expected to increase the effectiveness of the operating and administrative functions of the Trust.

For the year ended December 31, 2006 *($ millions)*	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Corporate	Total
Invested capital:						
Capital assets	**58.5**	**4.3**	**–**	**0.8**	**2.2**	**65.8**
Long-term investments and other assets	**–**	**–**	**4.3**	**–**	**1.4**	**5.7**
	58.5	**4.3**	**4.3**	**0.8**	**3.6**	**71.5**
Disposals						
Capital assets	**(0.8)**	**–**	**–**	**–**	**–**	**(0.8)**
Net invested capital	**57.7**	**4.3**	**4.3**	**0.8**	**3.6**	**70.7**

For the year ended December 31, 2006 *($ millions)*	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Corporate	Total
Invested capital:						
Maintenance	**5.0**	**0.8**	**–**	**0.3**	**–**	**6.1**
Growth	**53.3**	**3.4**	**4.3**	**0.2**	**0.8**	**62.0**
Administrative	**0.2**	**0.1**	**–**	**0.3**	**2.8**	**3.4**
	58.5	**4.3**	**4.3**	**0.8**	**3.6**	**71.5**
Disposals	**(0.8)**	**–**	**–**	**–**	**–**	**(0.8)**
Net invested capital	**57.7**	**4.3**	**4.3**	**0.8**	**3.6**	**70.7**

For the year ended December 31, 2005 *($ millions)*	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Corporate	Natural Gas Distribution	Total
Invested capital:							
Capital assets	53.4	1.6	–	1.4	3.5	10.8	70.7
Energy services arrangements, contracts and relationships	–	–	–	4.2	–	–	4.2
Long-term investments and other assets	–	–	–	–	14.9	0.4	15.3
	53.4	1.6	-	5.6	18.4	11.2	90.2
Disposals							
Capital assets	(7.1)	–	–	–	–	(203.0)	(210.1)
Long-term investments and other assets	–	–	–	–	(6.6)	(2.7)	(9.3)
Net invested capital	46.3	1.6	–	5.6	11.8	(194.5)	(129.2)

For the year ended December 31, 2005 *($ millions)*	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Corporate	Natural Gas Distribution	Total
Invested capital:							
Maintenance	2.0	1.4	–	1.1	–	3.5	8.0
Growth	50.8	0.2	–	4.4	15.6	7.1	78.1
Administrative	0.6	–	–	0.1	2.8	0.6	4.1
	53.4	1.6	–	5.6	18.4	11.2	90.2
Disposals	(7.1)	–	–	–	(6.6)	(205.7)	(219.4)
Net invested capital	46.3	1.6	–	5.6	11.8	(194.5)	(129.2)

FINANCIAL INSTRUMENTS

The Trust is exposed to market risk and potential loss from changes in the value of financial instruments. AltaGas enters into financial derivative contracts such as swaps and collars to manage exposure to fluctuations in commodity prices and interest rates, particularly in the Power Generation segment and with respect to interest rates on debt.

COMMODITY RISK

The Power Generation segment's results are significantly affected by the price of electricity in Alberta. AltaGas employs derivative commodity instruments for the purpose of managing the Trust's exposure to power price volatility. During 2006, the average monthly spot price ranged from a low of \$42.36/MWh in April to a high of \$174.09/MWh in October. The average all-hours spot price for 2006 was \$80.48/MWh, compared to \$70.19/MWh for 2005. The average hourly price ranged from \$5.42/MWh to \$999.99/MWh in 2006. The average sales price received by AltaGas for 2006 was \$69.26/MWh, compared to \$54.59/MWh for 2005. AltaGas has sold approximately two-thirds of its power forward for 2007 and a small portion for 2008 through 2013.

INTEREST RATE RISK

AltaGas reduces the effect of future interest rate movements on its cash flows through the use of interest rate swaps. At December 31, 2006 the Trust had interest rates fixed through swap transactions with varying terms to maturity on drawn bank debt of \$145.0 million. Including AltaGas' MTN and capital leases, the rate has been fixed on 96 percent of AltaGas' debt. The amount of fixed-rate debt was higher than the Trust's target of 70 to 75 percent of total debt due to the proceeds from the November 2005 NGD spin-out being applied to floating rate debt.

LIQUIDITY AND CAPITAL RESOURCES

AltaGas expects that funds from operations in 2007 will be sufficient to meet the Trust's distributions to unitholders and the majority of its budgeted maintenance and growth capital. The balance of its budgeted growth capital and a certain amount of unbudgeted acquisitions will be financed through the Distribution Reinvestment Program (DRIP) and existing bank lines. Should larger acquisitions require financing beyond existing sources, management is confident, based on historical success, that equity and debt capital markets could be accessed to provide additional financing. At this time AltaGas does not reasonably expect any currently known trend or uncertainty to affect the Trust's ability to access its historical sources of cash, except that cash from operations may be impacted by the proposed tax on the taxable component of the Trust's distribution proposed to begin with the 2011 taxation year.

CASH FLOWS *(\$ millions)*	**2006**	2005
Cash from operations	**146.9**	112.3
Investing activities	**(78.5)**	46.3
Financing activities	**(66.9)**	(159.2)
Change in cash and cash equivalents	**1.5**	(0.6)

CASH FROM OPERATIONS

Cash from operations reported on the Consolidated Statements of Cash Flows increased 31 percent to \$146.9 million in 2006, from \$112.3 million in 2005. The increase was primarily due to higher net income from the underlying operations in 2006 mainly in the Power Generation segment, compared to 2005. In 2005 net income included \$9.6 million related to gains on sale of assets and investments.

WORKING CAPITAL	December 31	
($ million except ratio amounts)	**2006**	2005
Current assets	**263.4**	252.3
Current liabilities	**239.7**	254.3
Working capital (deficiency)	**23.7**	(2.0)
Current ratio	**1.10**	0.99

INVESTING ACTIVITIES

During 2006 the Trust used cash for investing activities of $78.5 million compared to generating cash of $46.3 million from investing activities in 2005. Acquisition of capital assets and long-term investments and other assets totalled $78.1 million in 2006 compared to $58.7 million in 2005. A description of the acquisitions and investments comprising these amounts is in the Invested Capital section of this MD&A. In 2005 cash from investing activities was due to cash proceeds of $12.8 million received on the disposition of limited partnership units of Taylor, and $85.4 million received on the spin-out of the NGD segment.

FINANCING ACTIVITIES

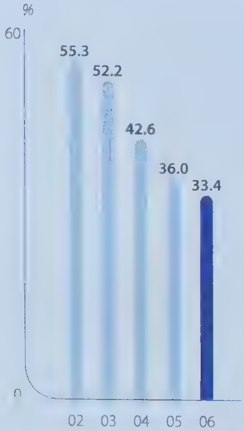
Cash used for financing activities was $66.9 million in 2006, a decrease of $92.3 million from $159.2 million used in 2005. The decrease in cash used for financing activities in 2006 was primarily due to the reduction in long-term debt as a result of proceeds received from the spin-out of the NGD segment in 2005. Significant financing activities in 2006 included $10.7 million higher distributions paid to unitholders than in 2005 and $18.8 million higher proceeds from the DRIP program partially offset by $2.6 million due to fewer unit options exercised in 2006 than in 2005.

CAPITAL RESOURCES

The use of debt or equity funding is based on AltaGas' capital structure, which is determined by considering the norms and risks associated with each of its business segments. At December 31, 2006 AltaGas had total debt outstanding of $265.5 million, down from $269.0 million as at December 31, 2005. At December 31, 2006, the Trust had $100.0 million in MTNs outstanding and had access to prime loans, bankers' acceptance and letters of credit through bank lines totalling $425.0 million. As at December 31, 2006 the Trust had drawn bank debt of $154.3 million and letters of credit outstanding of $66.3 million.

All of the borrowing facilities have financial tests and other covenants customary for these types of facilities, which must be met at each quarter-end. AltaGas has been in compliance with these covenants each quarter since the establishment of the facilities.

DEBT AS A PERCENT OF TOTAL CAPITALIZATION



On April 29, 2005 AltaGas filed a Universal Shelf Prospectus under which it may issue up to an aggregate of $500.0 million of Trust units or debt securities over a 25-month period. On August 30, 2005, $100.0 million of five-year MTNs were issued with a coupon of 4.41 percent.

AltaGas' target debt-to-total-capitalization ratio is 40 to 45 percent. The Trust's debt-to-total-capitalization ratio at December 31, 2006 was 33.4 percent, down from 36.0 percent at December 31, 2005.

The Dominion Bond Rating Service (DBRS) rates AltaGas Income Trust and the MTNs issued by AltaGas Income Trust at BBB (low). DBRS placed income trusts under review as a result of the Government of Canada's announcement on October 31, 2006 regarding proposed changes to the taxation of income trusts. In December 2006 DBRS confirmed AltaGas' MTN and stability ratings at BBB (low) and STA-3 (middle) respectively. The trend on the MTN rating was changed to Positive from Stable.

Standard & Poor's (S&P) rates the Trust's long-term corporate credit at BBB- with a stable outlook, and the senior unsecured debt at BBB-. In January 2007 S&P affirmed AltaGas' ratings.

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities and are indicators of the likelihood of payment and of the capacity of an entity to meet its financial commitment in accordance with the terms of the obligation. Stability ratings are intended to convey the opinion of a rating agency in respect of the relative stability and sustainability of an entity's distribution stream when compared to other stability rated entities.

CREDIT FACILITIES *($ millions)*	Borrowing capacity	**Drawn at December 31, 2006**	Drawn at December 31, 2005
Demand operating facility	50.0	**–**	2.7
Letter of credit facility, may borrow $25.0 million	75.0	**–**	–
Syndicated operating credit facility[1]	300.0	**154.3**	154.1
	425.0	**217.6**	194.1

[1] Extendible revolving-term credit facility that can be extended beyond the current term date of September 30, 2009 for an additional year.

At December 31, 2006 the Trust held a $75.0 million (2005 – $75.0 million) unsecured three-year extendible revolving letter of credit facility with a Canadian chartered bank maturing on September 30, 2009. AltaGas may borrow up to $25.0 million by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances on the letter of credit facility. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draw made. At December 31, 2006 the Trust had letters of credit of $63.3 million (2005 – $37.3 million) outstanding against the extendible revolving-term letter of credit facility and letters of credit of $3.0 million (2005 – $6.9 million) outstanding against the demand operating facility.

CONTRACTUAL OBLIGATIONS

		Payments due by period			
($ millions)	Total	Less than 1 year	1 – 3 years	4 – 5 years	After 5 years
Long-term debt	254.3	2.3	252.0	–	–
Capital leases	14.4	1.8	3.8	3.8	5.0
Operating leases	14.9	3.2	6.3	5.4	–
Total contractual obligations	283.6	7.3	262.1	9.2	5.0

AltaGas entered into a capital lease with Maxim Energy Group Ltd. for the right to 25 MW of gas-fired power peaking capacity and its related ancillary service and peaking sales revenues. The contract has a 10-year term commencing September 1, 2004 and includes an option at the end of the initial term to extend the term for a further 15 years or to purchase the assets. The net present value of the lease commitment at December 31, 2006 was $11.8 million (2005 – $12.3 million) with the balance due in monthly payments comprising principal and interest of $0.2 million.

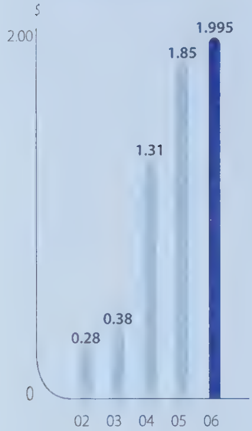
The Trust has long-term operating lease agreements for office space, office equipment and automotive equipment.

OTHER COMMITMENTS

Under the terms of a 1997 long-term gas supply contract the Trust is committed to supplying natural gas at prices ranging from $2.28/Mcf in 2006 to $2.40/Mcf by contract expiry in 2009. The Trust contracted with several producers to provide the volumes to fulfill this contract. One of those producers defaulted on its obligation under its gas supply contract in 1999, resulting in the delivery commitment for 2,845 Mcf/d being assumed by the Trust. The Trust owns natural gas reserves which it used as a hedge against the obligation under this supply contract. In December 2006 the Trust entered into a contract with a third party to fix the price of the gas supply related to this commitment until its expiry in 2009.

DISTRIBUTIONS

CASH DIVIDENDS/ DISTRIBUTIONS DECLARED PER UNIT



AltaGas' distributions are determined giving consideration to the ongoing sustainable distributable cash flow as impacted by the consolidated net income, maintenance and growth capital and debt repayment requirements of the Trust. AltaGas declared $110.8 million of distributions to unitholders in 2006 compared to $100.0 million in 2005. The Trust's distributable cash was $155.6 million in 2006 compared to $121.0 million in 2005 and was more than sufficient to fund all distributions to unitholders. The Trust targets to pay substantially all of its ongoing sustainable distributable cash through regular monthly distributions made to unitholders. (See Non-GAAP Financial Measures section of this MD&A for description of distributable cash).

The Trust commenced monthly distributions of $0.15 for each trust unit and each AltaGas LP #1 and AltaGas LP #2 Class B limited partnership unit (exchangeable unit) on June 15, 2004. AltaGas pays cash distributions on the 15th day of each month to unitholders of record on the 25th day of the previous month or, in each case, the following business day if the payment date or record date falls on a weekend or holiday.

The Trust's monthly cash distribution was increased to $0.16 per unit, an increase of 7 percent from $0.15 per unit, commencing with the distribution payable to unitholders of record on August 25, 2005.

On November 17, 2005 the Trust completed the spin-out of its wholly owned subsidiary AltaGas Utility Group Inc. as a separate, publicly traded entity. As part of the spin-out, the Trust distributed one common share of Utility Group (valued at $7.50 per share) for every 13.9592 trust and exchangeable units held on November 14, 2005.

On March 1, 2006 the Trust's monthly cash distribution was increased to $0.165 per unit commencing with the distribution payable to unitholders of record on March 27, 2006.

On August 9, 2006 the Trust's monthly cash distribution was increased to $0.17 per unit commencing with the distribution payable to unitholders of record on August 25, 2006. During 2006, AltaGas declared cash distributions of $1.995 per unit compared to $2.39 per unit (including the value of the November 14, 2005 distribution of shares) in 2005.

The following table summarizes AltaGas' dividend and distribution declaration history since 2004[1]:

($ per unit)	**2006**	2005	2004
First quarter	**0.485**	0.45	0.11
Second quarter	**0.495**	0.45	0.30
Third quarter	**0.505**	0.47	0.45
Fourth quarter	**0.510**	0.48	0.45
Distribution of shares[2]	**–**	0.54	–
	1.995	2.39	1.31

(1) Dividends were paid to shareholders from first quarter 2001 through first quarter 2004 prior to the reorganization of AltaGas Services Inc. into AltaGas Income Trust. The Trust conversion occurred effective May 1, 2004 and monthly distributions were declared to unitholders beginning that month.

(2) One share of Utility Group was issued for every 13.9592 trust and exchangeable units held on November 14, 2005.

On May 20, 2004, AltaGas adopted a Premium Distribution™, Distribution Reinvestment and Optional Unit Purchase Plan (DRIP) for eligible holders of trust units and exchangeable units of AltaGas Income Trust, AltaGas LP #1, and AltaGas LP #2. DRIP participation

generated $46.5 million in new equity through the issuance of 1.7 million Trust units for the year ended December 31, 2006. By December 31, 2006 the DRIP had contributed a total of $84.3 million of new equity and 3.4 million new units since inception of the Trust. Complete details on the DRIP are available on the AltaGas website at www.altagas.ca.

Assuming a unit was held throughout 2006, for income tax purposes the Trust expects approximately 73 percent of the total distributions declared in 2006 to be taxed as property income and 27 percent as return of capital. For most unitholders, the return of capital amount will reduce the cost base of their trust units for purposes of calculating the capital gains amount upon disposition of their units. Unitholders should seek independent tax advice in respect of the consequences to them of acquiring, holding and disposing of units.

TRUST UNIT INFORMATION

Under the terms of the restructuring of AltaGas into an income trust effective May 1, 2004, ASI security holders exchanged their shares in ASI for Trust units and eligible security holders also received exchangeable units that are exchangeable into Trust units on a one-for-one basis. The exchangeable units are not listed for trading on an exchange.

UNITS OUTSTANDING

At February 28, 2007 the Trust had 54.6 million Trust units and 2.1 million exchangeable units outstanding and a market capitalization of $1.5 billion based on a closing trading price on February 28, 2007 of $27.00 per Trust unit. At February 28, 2007 there were 1.0 million options outstanding and 150,525 options exercisable under the terms of the unit option plan.

CHANGES IN ACCOUNTING POLICIES

STOCK-BASED COMPENSATION FOR EMPLOYEES ELIGIBLE TO RETIRE BEFORE THE VESTING DATE

In July 2006 the Emerging Issues Committee (EIC) issued abstract No. 162, Stock-Based Compensation for Employees Eligible to Retire Before the Vesting Date. This EIC abstract clarifies that the compensation cost attributable to options and awards granted to employees who are eligible to retire or will become eligible to retire during the vesting period, should be recognized immediately if the employee is eligible to retire on the grant date or over the period between the grant date to the date the employee becomes eligible to retire. This EIC requires retroactive application to all unit-based compensation awards accounted for in accordance with the CICA Handbook Section 3870, Stock-Based Compensation and Other Stock-Based Payments. This differs from current practice that recognizes the expense over the period from the grant date to the vesting date. At December 31, 2006 AltaGas had no options outstanding that require retroactive application of this guidance.

NON-MONETARY TRANSACTIONS

The Canadian Institute of Chartered Accountants (CICA) issued Section 3831 "Non-Monetary Transactions". Under the new standard, a commercial substance test replaces the culmination-of-earnings test as the criterion for fair-value measurement. In addition, fair-value measurement is clarified. There was no material impact on the Trust's Consolidated Financial Statements.

FINANCIAL INSTRUMENTS

In January 2005 the CICA issued new accounting standards comprising handbook sections 1530, "Comprehensive Income", 3251, "Equity", 3855, "Financial Instruments – Recognition and Measurement" and 3865, "Hedges" which became effective January 1, 2007.

These standards provide guidance on the recognition, measurement and classification of financial assets, financial liabilities and non-financial derivatives. All financial assets, including derivatives, will be measured at fair value on the consolidated balance sheet with the exception of loans and receivables, held-to-maturity investments and certain private equity investments, which should be measured at amortized cost. Financial liabilities that are held for trading will be measured at fair value on the consolidated balance sheet. Other financial liabilities will be measured at amortized cost.

The new standards also establish the accounting requirements for hedges. Any hedge ineffectiveness will be recognized immediately in income.

Accumulated other comprehensive income (AOCI) will be included on the consolidated balance sheet as a separate component of unitholders' equity.

The changes in carrying value of financial instruments and related deferred balances as a result of adopting these new standards will be recognized in opening accumulated earnings and in opening AOCI as at January 1, 2007.

CRITICAL ACCOUNTING ESTIMATES

Since a determination of the value of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of the Trust's Consolidated Financial Statements requires the use of estimates and assumptions which have been made using careful judgment. AltaGas' significant accounting policies are contained in the Notes to the Consolidated Financial Statements. Certain of these policies involve critical accounting estimates as a result of the requirement to make particularly subjective or complex judgments about matters that are inherently uncertain and because of the likelihood that materially different amounts could be reported under different conditions or using different assumptions.

AltaGas' critical accounting estimates continue to be amortization expense, asset retirement obligations and asset impairment assessment. The following section describes the critical accounting estimates and assumptions that AltaGas has made and how they affect the amounts reported in the Consolidated Financial Statements.

AMORTIZATION

AltaGas performs assessments of amortization of capital assets and energy services arrangements, contracts and relationships. When it is determined that assigned asset lives do not reflect the estimated remaining period of benefit, prospective changes are made to the depreciable lives of those assets. Oil and gas capitalized costs are depleted (amortized) to income on a unit-of-production basis over the estimated production life of proved reserves. Amortization is a critical accounting estimate because:

- There are a number of uncertainties inherent in estimating the remaining useful life of certain assets;
- There is also uncertainty related to assumptions about reserve quantities; and
- Changes in these assumptions could result in material adjustments to the amount of amortization that the Trust recognizes from period to period.

ASSET RETIREMENT OBLIGATIONS AND OTHER ENVIRONMENTAL COSTS

The Trust records liabilities relating to asset retirement obligations and other environmental matters. Asset retirement obligations and other environmental costs are critical accounting estimates because:

- The majority of the asset retirement costs will not be incurred for a number of years (most are estimated between 2025 and 2035), requiring the Trust to make estimates over a long period of time;
- Environmental laws and regulations could change, resulting in a change in the amount and timing of expenses anticipated to be incurred; and
- A change in any of these estimates could have a material impact on the Trust's Consolidated Financial Statements.

ASSET IMPAIRMENT

AltaGas reviews long-lived assets and intangible assets with finite lives whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Recoverability is determined based on an estimate of undiscounted cash flows, and measurement of an impairment loss is determined based on the fair value of the assets. This is a critical accounting estimate because:

- It requires management to make assumptions about future cash inflows and outflows over the life of an asset, which are susceptible to changes from period to period due to changing information available related to the determination of the assumptions; and
- The impact of recognizing an impairment may be material to the Trust's financial statements.

With respect to impairment assessment, management has made fair-value determinations related to goodwill, estimating future cash flows as well as appropriate discount rates. The estimates have been applied consistently with prior periods.

OFF-BALANCE-SHEET ARRANGEMENTS

The Trust is not party to any contractual arrangement under which an unconsolidated entity may have any obligation under certain guarantee contracts, a retained or contingent interest in assets transferred to an unconsolidated entity or similar arrangement that serves as credit, liquidity or market risk support to that entity for such assets. The Trust has no obligation under derivative instruments, or a material variable interest in an unconsolidated entity that provides financing, liquidity, market risk or credit risk support or engages in leasing, hedging or research and development services with the Trust.

RELATED PARTIES

The Trust sold $84.0 million of natural gas to, and incurred transportation costs of $0.6 million charged by Utility Group in 2006. The Trust also paid management fees of $1.0 million to, and received management fees of $30,000 from, Utility Group for administrative services. In addition, the Trust provided $0.5 million of operating services to Utility Group.

The Trust pays rent under a lease for office space and equipment to 2013761 Ontario Inc., which is owned by an employee. Payments of $83,094 were made in 2006 (2005 – $81,535). The five-year lease expires in 2007 and is renewable at the option of AltaGas for another three years. (See note 17 of the Consolidated Financial Statements.)

DISCLOSURE CONTROLS AND PROCEDURES

The Trust maintains disclosure controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under applicable securities legislation is accumulated and communicated to management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

In accordance with Multilateral Instrument 52-109 (Certification of Disclosure in Issuers' Annual and Interim Filings), management carried out an evaluation, under the supervision and with the participation of management, including the Chairman, President and Chief Executive Officer and the Chief Financial Officer, of the effectiveness of disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that disclosure controls and procedures were effective as of December 31, 2006 to provide reasonable assurance that information required to be disclosed is recorded, processed, summarized, and reported within the time periods specified in the applicable rules and forms of applicable securities legislation.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

Management of the Trust is responsible for establishing and maintaining adequate internal controls over financial reporting. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be designed effectively can provide only reasonable assurance with respect to financial statement preparation and presentation.

The Trust has used the Committee of Sponsoring Organizations of the Treadway Commission (COSO) framework to evaluate the design of internal controls over financial reporting.

At December 31, 2006 management assessed the design of the Trust's internal control over financial reporting and concluded that internal control over financial reporting is suitably designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. The assessment also concluded that there were no material weaknesses in the design of AltaGas' internal control over financial reporting that have been identified by management.

There have been no changes in the design of internal control over financial reporting during the year ended December 31, 2006 that have materially affected or are reasonably likely to materially affect the Trust's internal control over financial reporting.

UNITHOLDER LIMITED LIABILITY LEGISLATION

On July 1, 2004 the Income Trusts Liability Act (Alberta) came into force, which provides that a unitholder will not be, as a beneficiary, liable for any act, default, obligation or liability of the Trustee that arises after the particular provision of such legislation comes into force.

The AltaGas Income Trust indenture itself provides that no unitholder will be subject to any liability in connection with the Trust or its obligations and affairs or for any act or omission of the Trustee of the Trust, provided that in the event that a court determines that unitholders are subject to such liabilities, the liabilities will be enforceable only against and will be satisfied out of the Trust's assets. The Trust indenture also provides that contracts to which the Trust is a party should contain language restricting the liability of unitholders.

SUBSEQUENT EVENT

On January 19, 2007 AltaGas completed a $100.0 million issue of senior unsecured MTNs. The notes carry a coupon rate of 5.07 percent and mature on January 19, 2012.

TAX ON INCOME TRUSTS

On October 31, 2006 the Government of Canada announced proposed changes to the taxation of certain publicly-traded trusts and partnerships and their unitholders. Generally, the proposed changes would not take effect until January 1, 2011, provided the entity experiences only "normal growth" and no "undue expansion" before then. Pursuant to the proposed changes, certain income distributions by the Trust would become subject to taxes and would be treated as dividends paid by a taxable Canadian corporation to unitholders. Draft legislation to implement this tax was released for comment on December 21, 2006. Management intends to adapt the Trust's corporate organizational strategies as the tax legislation evolves, with the goal of growing unitholder value.

FOURTH QUARTER HIGHLIGHTS

Net income for the quarter ended December 31, 2006 was $27.3 million ($0.49 per unit) compared to $26.4 million ($0.48 per unit) for the same period in 2005. Net income increased as a result of higher power revenues on both hedged and unhedged power volumes, lower power transmission costs, higher NGL frac spreads and extraction volumes, and lower interest expense, partially offset by higher expenses in the Corporate segment, lower revenue in the transmission business and a write-down of

goodwill related to a non-core investment in the FG&P segment. Fourth quarter 2005 included the contribution from the Genesee power contract and approximately six weeks of earnings from the NGD segment, as well as an income tax recovery related to the adjustment of future tax balances.

On a consolidated basis, net revenue for the quarter ended December 31, 2006 was $84.6 million compared to $78.7 million for the same period in 2005. The increase was mainly due to higher revenue from both power hedges and spot sales and lower transmission costs in the Power Generation segment ($11.9 million), new plants in the FG&P segment ($3.0 million) and higher NGL frac spreads and higher volumes processed at the extraction plants ($1.0 million). The increases in net revenue were reduced as a result of the spin-out of the NGD business in November 2005 ($4.2 million), the expiration of the Genesee power contract in March 2006 ($2.1 million), lower throughput in the FG&P segment ($1.4 million), as well as $1.5 million in a capital payout in fourth quarter 2005 and $0.8 million of revenue deferred in the transmission business.

Operating and administrative expense for the quarter ended December 31, 2006 was $40.1 million compared to $38.9 million for the same period in 2005. The increase was primarily due to additional costs from new FG&P facilities, higher compensation costs and general cost escalations. The increases were partially offset by the spin-out of the NGD segment which reported operating and administrative costs of $2.2 million in the fourth quarter of 2005.

Amortization expense for the quarter ended December 31, 2006 was $12.5 million compared to $10.9 million for the same period in 2005. The increase was primarily due to higher amortization of energy services contracts and relationships of $0.9 million, higher depletion and depreciation rates in oil and gas production ($0.6 million), the write-off of $0.6 million in goodwill related to a non-core investment in the FG&P segment, and growth in the FG&P segment of $0.9 million. The increases were partially offset by lower amortization of $0.8 million due to the spin-out of the NGD segment in the fourth quarter of 2005.

Interest expense in the fourth quarter of 2006 was $3.3 million compared to $3.9 million for the same quarter in 2005. The decrease was due to higher funds from operations and lower average debt balances as a result of $85.4 million of debt repayment in late 2005 that was made using the proceeds of the spin-out of the NGD segment.

Income taxes for the quarter ended December 31, 2006 were $1.4 million compared to recoveries of $1.3 million for the same period in 2005. The increased income tax expense was due to higher net income before taxes in the fourth quarter of 2006, as well as an adjustment of the future tax balances which resulted in an income tax recovery of $1.6 million in fourth quarter 2005.

SENSITIVITY ANALYSIS

The following table illustrates the anticipated effects of possible economic and operational changes on AltaGas' expected 2007 net income.

Factor	Increase or decrease	Increase or decrease in net income per unit
Field gathering and processing volumes at existing facilities	5 Mmcf/d	0.016
Field gathering and processing operating margin per Mcf	1 cent /Mcf	0.024
Electricity prices	$1/MWh	0.015
Natural gas prices	$0.50/GJ	0.006
Natural gas liquids fractionation spread	$1 per Bbl	0.007
Interest rates	25 bps	0.001

SUMMARY OF CONSOLIDATED RESULTS FOR THE EIGHT MOST RECENTLY COMPLETED QUARTERS

($ millions)	**Q4-06**	Q3-06	Q2-06	Q1-06	Q4-05	Q3-05	Q2-05	Q1-05
Net revenue[1]	**84.6**	82.5	72.8	79.1	78.7	71.3	67.5	79.4
Operating income[1]	**32.0**	33.7	26.0	35.0	29.0	22.9	22.0	34.2
Net income	**27.3**	28.8	29.9	28.6	26.4	17.2	19.1	27.6

($ per unit)	**Q4-06**	Q3-06	Q2-06	Q1-06	Q4-05	Q3-05	Q2-05	Q1-05
Net income								
Basic	**0.49**	0.52	0.54	0.52	0.48	0.32	0.35	0.52
Diluted	**0.49**	0.52	0.54	0.52	0.48	0.32	0.35	0.52
Distributions declared[2]	**0.51**	0.505	0.495	0.485	0.48	0.47	0.45	0.45

(1) Non-GAAP financial measure. See discussion in Non-GAAP Financial Measures in this and previously filed disclosures.

(2) Excludes share distribution as a result of the spin-out of the NGD segment. The Trust issued one common share of Utility Group (valued at $7.50 per share) for every 13.9592 trust and exchangeable units held on November 14, 2005, providing additional value of $0.54 per unit.

Identifiable trends in AltaGas' business in the past eight quarters reflect: the organization's internal growth, acquisitions, a favourable business environment including generally increasing power prices in Alberta, seasonality in the NGD business up to the time of its spin-out in November 2005, and asset dispositions.

Significant items that impacted individual quarterly earnings were as follows:

- Net income for first quarter 2005 included a $7.9 million after-tax gain related to the change in the Trust's ownership interest in Taylor;
- Second quarter 2005 net income included an after-tax loss of $0.4 million related to the Trust's ownership interest in Taylor;
- Results in fourth quarter 2005 were impacted by the spin-out of the NGD segment, the net after-tax impact of which was $0.1 million. In addition, operating income was approximately $2 million lower due to owning 100 percent of the NGD segment for only six weeks in the quarter and a $1.6 million tax recovery due to an adjustment to future tax balances. Results were also impacted by higher prices received for power sold and lower interest expense;
- Results in the FG&P segment are typically lower in the first quarter compared to the fourth quarter;
- Strong power prices, higher frac spreads and lower interest expense in all quarters in 2006 resulted in strong financial results which were partially offset by the contribution from the NGD segment in first quarter 2005 which was spun out in November 2005;
- In second quarter 2006 a $6.6 million non-cash future income tax benefit was recorded as a result of a reduction in the federal and Alberta corporate income tax rates; and
- In fourth quarter 2006 the Trust reported $0.6 million in goodwill write-down and deferred $0.8 million in revenue in the transmission business.

MANAGEMENT'S RESPONSIBILTY FOR **FINANCIAL STATEMENTS**

Management recognizes that it is responsible for the preparation of the Consolidated Financial Statements and is satisfied that these statements have been prepared using Canadian generally accepted accounting principles and are within reasonable limits of materiality. Further, management is satisfied that the financial information contained in this annual report is consistent with that presented in the Consolidated Financial Statements. The internal controls and systems of AltaGas Income Trust (AltaGas of the Trust) are designed to provide reasonable assurance that its assets are safeguarded and to facilitate the preparation of relevant, reliable and timely information. Independent auditors have been engaged by the Trust to examine the Consolidated Financial Statements. The Consolidated Financial Statements are approved by the Board of Directors after considering the recommendation of the Audit Committee. The Audit Committee of the Board of Directors is composed of directors who are not officers or employees. The Consolidated Financial Statements and MD&A are discussed and reviewed by the Audit Committee with management and the independent auditors before such information is approved by the Committee and recommended to the Board of Directors for approval. The Board of Directors, on the recommendation of the Audit Committee, has approved the Consolidated Financial Statements contained in this report.

DAVID W. CORNHILL
Chairman, President and
Chief Executive Officer of
AltaGas General Partner Inc.,
delegate of the Trustee of
AltaGas Income Trust

March 8, 2007

RICHARD M. ALEXANDER
Executive Vice President
Chief Operating Officer and
Chief Financial Officer of
AltaGas General Partner Inc.,
delegate of the Trustee of
AltaGas Income Trust

March 8, 2007

AUDITORS' **REPORT**

TO THE UNITHOLDERS OF ALTAGAS INCOME TRUST

We have audited the consolidated balance sheets of AltaGas Income Trust as at December 31, 2006 and 2005 and the consolidated statements of income and accumulated earnings and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of AltaGas Income Trust as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

ERNST & YOUNG LLP
Chartered Accountants

February 23, 2007
Calgary, Canada

CONSOLIDATED **BALANCE SHEETS**

As at December 31 *($ thousands)*	2006	2005
ASSETS		
Current assets		
Cash and cash equivalents	**$ 13,226**	$ 11,685
Accounts receivable	**224,533**	220,684
Inventory	**61**	95
Customer deposits	**16,304**	15,371
Other	**9,277**	4,421
	263,401	252,256
Capital assets *(notes 3 and 8)*	**677,941**	645,442
Energy services arrangements, contracts and relationships *(note 4)*	**103,330**	110,850
Goodwill *(note 5)*	**18,260**	18,860
Long-term investments and other assets *(note 6)*	**46,643**	40,921
	$ 1,109,575	$ 1,068,329
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities	**$ 200,882**	$ 215,601
Distributions payable to unitholders	**9,588**	8,744
Short-term debt *(note 7)*	**–**	2,710
Current portion of long-term debt *(note 8)*	**1,147**	1,071
Customer deposits	**16,304**	15,371
Deferred revenue	**788**	–
Other current liabilities	**10,982**	10,773
	239,691	254,270
Long-term debt *(note 8)*	**264,340**	265,245
Asset retirement obligations *(note 9)*	**23,350**	16,982
Future income taxes *(note 10)*	**51,252**	52,433
Other long-term liabilities	**1,526**	813
	580,159	589,743
Unitholders' equity *(notes 12 and 13)*	**529,416**	478,586
	$ 1,109,575	$ 1,068,329

Commitments *(notes 7, 8, 11, 14 and 16)*

See accompanying notes to the Consolidated Financial Statements.

Approved by the Board of Directors of AltaGas General Partner Inc. on behalf of AltaGas Income Trust:

DAVID W. CORNHILL
Director

Robert B. Hodgins

ROBERT B. HODGINS
Director

CONSOLIDATED **STATEMENTS OF INCOME AND ACCUMULATED EARNINGS**

For the years ended December 31 *($ thousands except per unit amounts and number of units)*	2006	2005
REVENUE		
Operating	**$ 1,358,189**	$ 1,491,621
Other *(note 19)*	**4,415**	10,725
	1,362,604	1,502,346
EXPENSES		
Cost of sales	**1,043,691**	1,205,481
Operating and administrative	**145,788**	141,382
Amortization:		
Capital assets	**38,377**	40,886
Energy services arrangements, contracts and relationships	**7,484**	6,486
Goodwill impairment *(note 5)*	**600**	–
	1,235,940	1,394,235
Operating income	**126,664**	108,111
Interest expense *(notes 7, 8 and 11)*		
Short-term debt	**270**	576
Long-term debt	**13,012**	18,515
Income before income taxes	**113,382**	89,020
Income tax recovery *(note 10)*	**(1,129)**	(1,268)
Net income	**114,511**	90,288
Accumulated earnings, beginning of year	**287,107**	196,819
Accumulated earnings, end of year	**$ 401,618**	$ 287,107
Net income per unit *(note 13)*		
Basic	**$ 2.06**	$ 1.67
Diluted	**$ 2.06**	$ 1.67
Weighted average number of units outstanding (thousands) *(note 13)*		
Basic	**55,469**	54,011
Diluted	**55,516**	54,088

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED **STATEMENTS OF CASH FLOWS**

For the years ended December 31 *($ thousands)*	2006	2005
Cash from operations		
Net income	$ 114,511	$ 90,288
Items not involving cash:		
Amortization	45,861	47,372
Accretion of asset retirement obligations *(note 9)*	1,430	1,326
Unit-based compensation *(note 13)*	482	16
Future income tax recovery *(note 10)*	(1,181)	(3,364)
Gain on sale of assets and investment transactions *(note 6)*	–	(9,573)
Equity income	(3,967)	(1,141)
Distributions from equity investments	2,950	2,874
Goodwill impairment *(note 5)*	600	–
Other	994	1,240
Funds from operations	161,680	129,038
Asset retirement obligations settled *(note 9)*	(560)	(183)
Net change in non-cash working capital *(note 15)*	(14,260)	(16,545)
	146,860	112,310
Investing activities		
Decrease (increase) in customer deposits	(933)	1,547
Acquisition of capital assets	(73,042)	(53,965)
Disposition of capital assets	509	5,030
Acquisition of energy services arrangements, contracts and relationships	–	(3,868)
Disposition of energy services arrangements, contracts and relationships	36	–
Acquisition of long-term investments and other assets	(5,032)	(855)
Disposition of long-term investments and other assets *(note 6)*	–	13,027
Proceeds on spin-out of Natural Gas Distribution segment *(note 20)*	–	85,383
	(78,462)	46,299
Financing activities		
Decrease in short-term debt	(2,710)	(4,235)
Decrease in long-term debt	(829)	(86,217)
Distributions to unitholders	(109,954)	(99,249)
Net proceeds from issuance of units *(note 13)*	46,636	30,476
	(66,857)	(159,225)
Change in cash and cash equivalents	1,541	(616)
Cash and cash equivalents, beginning of year	11,685	12,301
Cash and cash equivalents, end of year	$ 13,226	$ 11,685

See accompanying notes to the Consolidated Financial Statements.

NOTES TO THE **CONSOLIDATED FINANCIAL STATEMENTS**

(Tabular amounts in thousands of dollars unless otherwise indicated.)

1. STRUCTURE OF ALTAGAS INCOME TRUST

AltaGas Income Trust (AltaGas or the Trust) is an unincorporated open-ended investment trust governed by the laws of Alberta and created pursuant to a Declaration of Trust dated March 26, 2004. The Trust indirectly holds all of the assets, liabilities and businesses formerly held by AltaGas Services Inc. (ASI). Effective May 1, 2004 the business of ASI was reorganized pursuant to a Plan of Arrangement and holders of common shares of ASI received Trust units and/or AltaGas Holding Limited Partnership No. 1 (AltaGas LP #1) or AltaGas Holding Limited Partnership No. 2 (AltaGas LP #2) Class B limited partnership units (exchangeable units) in exchange for their common shares. ASI became an indirect subsidiary of the Trust and was amalgamated with a number of its subsidiaries to form AltaGas Ltd. The operational and financial results presented report on a continuity-of-interest accounting basis which recognizes the Trust as the successor to ASI.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These Consolidated Financial Statements are prepared by management in accordance with Canadian generally accepted accounting principles (GAAP). Significant accounting policies are summarized below:

Basis of Presentation

These Consolidated Financial Statements include the accounts of AltaGas Income Trust and all of its wholly owned subsidiaries, and its proportionate interests in various partnerships and joint ventures. Transactions between the Trust and its wholly owned subsidiaries and the proportionate interests are eliminated on consolidation.

On November 17, 2005 AltaGas completed the spin-out of AltaGas Utility Group Inc. (Utility Group), as described in note 20. Prior to the spin-out, this business was owned by AltaGas. Subsequent to the spin-out AltaGas retained a 26.7 percent interest in the common shares of Utility Group. The revenue, expenses and cash flows of the Natural Gas Distribution (NGD) business were consolidated up to November 17, 2005. Subsequent to the completion of the spin-out, AltaGas accounts for its interest in Utility Group as an equity investment.

Business Combinations

All business combinations are accounted for using the purchase method. Under the purchase method assets and liabilities of the acquired entity are recorded at fair value. The excess of the purchase price over the fair value of the assets and liabilities acquired is recorded as goodwill.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand and balances with banks and investments in money market instruments with original maturities of less than three months.

Inventory

Inventory consists of materials and supplies and is valued at the lower of average cost and replacement cost.

Customer Deposits

Cash deposited by customers under the terms of natural gas and power agency arrangements is invested in short-term deposits with a Canadian chartered bank. These funds are restricted and are not available for general use by the Trust. The corresponding liability is classified as customer deposits within current liabilities.

Capital Assets and Amortization

Capital assets are recorded at cost plus interest incurred during the construction period to finance long-term construction projects. Repairs and maintenance costs are expensed in the period incurred.

Prior to the spin-out of the Trust's NGD business on November 17, 2005, the allowance for funds used during the construction of regulated natural gas distribution assets was capitalized at rates authorized by the regulatory authorities in Alberta and Nova Scotia. Contributions in aid of construction of natural gas distribution assets were deducted from the cost of acquiring capital assets, with subsequent amortization calculated on the net cost.

The Trust amortizes the cost of capital assets, net of salvage value, on a straight-line basis based on the estimated useful life of the assets, except for regulated natural gas distribution assets, where amortization was calculated on a straight-line basis at rates approved by the regulatory authority, and for energy services assets where AltaGas follows the full cost method of accounting for oil and natural gas exploration and development activities. Capitalized costs are accumulated and amortized to income on a unit-of-production basis over the estimated production life of proved reserves.

Field Gathering and Processing	
Gathering and processing assets	15 – 25 years
Other assets	1 – 5 years
Extraction and Transmission	
Extraction and transmission assets	15 – 40 years
Power Generation	
Assets under capital lease	10 years
Energy Services	
Energy services assets	unit of production
Other assets	1 – 5 years
Natural Gas Distribution	
Natural gas distribution assets	0.9 – 25.7 percent
Other assets	3.1 – 57.9 percent
Corporate	
Other assets	1 – 5 years

Leases are classified as either capital or operating. Leases which transfer substantially all the benefits and risks of ownership of property to AltaGas are accounted for as capital leases. Assets under capital leases are accounted for as assets and are amortized on a straight-line basis over the lease term. The capital lease obligations reflect the present value of future lease payments. The finance element of the lease payments is charged to income over the term of the lease. Commitments to repay the principal amounts arising under capital lease obligations are included in current liabilities to the extent that the amount is repayable within one year; otherwise the principal is included as a long-term liability.

Energy Services Arrangements, Contracts, Relationships and Amortization

Energy services arrangements, contracts and relationships are recorded at cost, which was fair value at the time of purchase, and are amortized on a straight-line basis over their term or estimated useful life:

Sundance B Power Purchase Arrangements (PPAs)	19 years
Natural gas and power marketing contracts	18 – 49 months
Energy services relationships	15 years

AltaGas owns 50 percent of two Sundance B PPAs through its interest in the ASTC Power Partnership (ASTC). ASTC is committed to purchase all of the power from the two 353-MW capacity Sundance B generating units. The investment in the PPAs and the corresponding revenue and expenses are recorded on a proportionate basis. The Sundance B PPAs required a capital outlay to acquire. The Trust is obligated to make payments to the owners of the underlying generating units over the remaining terms of the PPAs to December 31, 2020. Such amounts are recorded as cost of sales as incurred. Revenue from the sale of the power is recorded when delivered.

The Genesee power purchase arrangement, or PPA, had the right to generating capacity at a regulated Alberta generating unit for a three-year period that ended March 31, 2006. This PPA required no capital outlay but included monthly capacity charges, which amounts were recorded as cost of sales. Revenue from the sale of the committed power was recorded when delivered.

The natural gas and power marketing contracts are the rights and obligations to buy and sell fixed volumes of natural gas and power at contracted prices. Revenue and expenses are recorded when product is delivered.

Energy services relationships were purchased along with substantially all of the assets and liabilities of iQ2 Power Corp. (iQ2), PremStar Energy Canada Ltd., ECNG Inc. and Energistics Group Inc. and are recorded at fair value and amortized on a straight-line basis commencing with the expiration of the related short-term marketing contracts over the 15-year expected useful life of the relationships.

Goodwill

Goodwill represents that portion of the purchase price on acquisition which was in excess of the fair value of the net assets acquired. Goodwill is not subject to amortization but is tested at least annually for impairment by comparing the fair value of the reporting unit with its book value. If the carrying value of the reporting unit exceeds fair value, the implied fair value of goodwill is determined. Any excess of the carrying value of goodwill over its implied fair value is recorded as an impairment charge to income.

Long-Term Investments and Other Assets

Investments in entities in which AltaGas has the ability to exercise significant influence are accounted for by the equity method. Other long-term investments are recorded at cost. Any impairment in value of an investment that is other than temporary is charged against income when determined.

Development Costs

The Trust expenses development costs as incurred unless such development costs meet certain criteria related to technical, market, and financial feasibility for capitalization. Development costs are examined annually to ensure capitalization criteria are still met. When the criteria that previously justified the deferral of costs are no longer met, the unamortized balance is taken as a charge to income in the period when this determination is made. Development costs are amortized based on the expected period and pattern of benefit, beginning at the commencement of commercial operations.

Asset Retirement Obligations

The Trust recognizes asset retirement obligations in the period in which an obligation is incurred and a reasonable estimate of a fair value can be determined. The associated asset retirement costs are capitalized as part of the carrying amount of the asset and are depreciated over the estimated useful life of the asset. The liability is increased due to the passage of time over the estimated period until the settlement of the obligation, with a corresponding charge to operating and administrative expense in the income statement.

In the Extraction and Transmission (E&T) segment, certain assets have an indeterminate life and thus a retirement obligation is not recognized.

Derivative Instruments

AltaGas enters into financial derivative contracts such as swaps and collars to manage exposure to fluctuations in commodity prices and interest rates. These contracts are designated as hedges when the underlying risks of the hedged item and hedging instruments offset to manage the Trust's exposure. Gains and losses relating to such contracts are deferred and recognized in the same period and financial statement category as the corresponding hedged transaction. If financial derivative contracts cease to be effective as hedges or if the hedge relationship is terminated, any cumulative gains or losses arising prior to such time continue to be deferred over the period of the original hedged transaction and subsequent changes in the fair value of the derivative contracts are recognized as adjustments to income. The effectiveness of hedges is tested quarterly to ensure the correlation of the underlying risks. AltaGas enters into commodity derivative contracts for the future delivery of commodities at fixed prices. These contracts are not recognized in the financial statements until they are settled.

Revenue Recognition

In the Field Gathering and Processing (FG&P) segment and transmission business, revenue is recorded as the services are rendered. In the extraction business, Power Generation, Energy Services and NGD segments, revenue is recognized at the time the product or service is delivered.

Unit-Based Compensation Plans

The Trust follows the fair value based method of accounting for Trust unit options granted during the year. Unit options are valued at the date of the grant and recognized as compensation expense over the vesting period of the options. Consideration received by the Trust on exercise of the option rights is credited to unitholders' capital.

AltaGas has a Mid-Term Incentive Plan in which participants receive phantom units requiring settlement by cash payments. During the graded vesting period, compensation expense is recognized using the liability method and is recorded as operating and administrative expense over the vesting period. A change in value of the vested phantom units is recognized in the period the change occurs.

Pension Plans and Retiree Benefits

The cost of defined benefit pension and other retirement benefits is actuarially determined using the projected benefit method prorated on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. The current service cost of the benefit is the sum of the individual current service costs and the accrued benefit obligation is the sum of the accrued liabilities for all participants.

For purposes of calculating the expected return on plan assets, those assets are valued at fair value. The cumulative net actuarial gain or loss at the beginning of the year in excess of 10 percent of the greater of the accrued benefit obligation and the fair value of plan assets is amortized on a straight-line basis over the average remaining service life of the active employees. The average remaining service periods of the active members covered by the defined benefit pension plans are nine to 12 years. Transitional obligations are being amortized on a straight-line basis over the remaining service life of active employees. Past service costs resulting from plan amendments are amortized on a straight-line basis over the average remaining service life of active employees for the respective plan.

Income Taxes

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable on income in a particular taxation year that is not paid or payable to the unitholders in such taxation year. As the Trust allocates all of its Canadian taxable income to the unitholders in accordance with its Trust indenture and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for Canadian income tax expense has been made for the Trust.

Income taxes are calculated in the subsidiary companies of the Trust using the liability method of tax accounting. Under this method, future income tax assets and liabilities are determined based on differences between the financial reporting and tax bases of assets and liabilities and are measured using the substantively enacted tax rates and laws that are anticipated to be in effect in the periods in which the differences are expected to be settled or realized.

Prior to the spin-out of Utility Group by the Trust on November 17, 2005, income taxes in the rate-regulated natural gas distribution subsidiaries were provided using the taxes payable method approved by the regulatory authorities. In accordance with regulated accounting, provision was made only for those income taxes currently payable and no future tax was recorded on the differences between the financial reporting and tax bases of assets and liabilities.

Related Party Transactions

Transactions with related parties that are conducted in the normal course of operations have been recorded at the exchange amount.

Per Unit Information

Basic net income per unit is calculated on the basis of the weighted average number of trust and exchangeable units outstanding during the year. Diluted net income per unit is calculated as if the proceeds obtained upon exercise of options were used to purchase units at the average market price during the period.

Use of Estimates and Measurement Uncertainty

The preparation of consolidated financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenue and expenses during the period. Key areas where management has made complex or subjective judgments, as a result of matters that are inherently uncertain, include among others, the fair value of certain assets including long-lived assets and goodwill; recoverability of investments; litigation; environmental and asset retirement obligations; pensions and other post-retirement benefits; unit-based compensation; and income taxes. By their nature, these estimates are subject to measurement uncertainty and may impact the financial statements of future periods.

Regulation

Until November 17, 2005 AltaGas Utilities Inc. (AUI) was wholly owned by AltaGas. AUI engages in the distribution and sale of natural gas in various communities in Alberta and is regulated by the Alberta Energy and Utilities Board (EUB). The EUB exercises statutory authority over matters such as rates, financing, accounting, construction and contracts with customers. In order to recognize the economic effect of the actions and decisions of the EUB, the timing of recognition of certain revenue and expenses may differ from that otherwise expected under GAAP for non rate-regulated entities.

3. CAPITAL ASSETS

	2006			2005		
	Cost	**Accumulated amortization**	**Net book value**	Cost	Accumulated amortization	Net book value
Field Gathering and Processing						
Field gathering and processing assets	**$ 558,411**	**$ (128,643)**	**$ 429,768**	$ 496,284	$ (106,082)	$ 390,202
Other assets	**2,860**	**(1,402)**	**1,458**	2,692	(680)	2,012
Extraction and Transmission						
Extraction and transmission assets	**250,933**	**(38,023)**	**212,910**	246,615	(30,295)	216,320
Power Generation						
Capital lease *(note 8)*	**13,798**	**(3,216)**	**10,582**	13,798	(1,836)	11,962
Energy Services						
Energy services assets	**30,177**	**(15,250)**	**14,927**	28,886	(12,315)	16,570
Other assets	**1,990**	**(385)**	**1,605**	1,576	(280)	1,297
Corporate						
Other assets	**16,962**	**(10,271)**	**6,691**	14,774	(7,695)	7,079
	$ 875,131	**$ (197,190)**	**$ 677,941**	$ 804,625	$ (159,183)	$ 645,442

Interest capitalized on long-term capital construction projects for the year ended December 31, 2006 was $nil (December 31, 2005 – $nil). At December 31, 2006 the Trust had spent approximately $14.9 million (December 31, 2005 – $18.6 million) on capital projects under construction that were not yet subject to amortization.

4. ENERGY SERVICES ARRANGEMENTS, CONTRACTS AND RELATIONSHIPS

	2006			2005		
	Cost	**Accumulated amortization**	**Net book value**	Cost	Accumulated amortization	Net book value
Energy services arrangements and contracts	**$ 115,071**	**$ (31,497)**	**$ 83,574**	$ 115,056	$ (25,149)	$ 89,907
Energy services relationships	**20,892**	**(1,136)**	**19,756**	20,943	–	20,943
	$ 135,963	**$ (32,633)**	**$ 103,330**	$ 135,999	$ (25,149)	$ 110,850

The amortization of the energy services relationships began in 2006 upon expiration of the corresponding short-term marketing contracts.

5. GOODWILL

	2006	2005
Balance, beginning of year	**$ 18,860**	$ 18,860
Goodwill impairment	**(600)**	–
Balance, end of year	**$ 18,260**	$ 18,860

Through its annual goodwill impairment testing AltaGas determined that the fair value of an investment in a business ancillary to the FG&P segment was less than the book value and recorded an impairment charge to goodwill of $0.6 million in 2006.

6. LONG-TERM INVESTMENTS AND OTHER ASSETS

	2006	2005
Units of public trusts	**$ 375**	$ 375
Equity-accounted investments in public entities	**40,071**	39,098
Deferred debt costs, net of amortization	**759**	1,042
Deferred development costs	**4,332**	–
Loans receivable – BMWLP	**700**	–
Other	**406**	406
	$ 46,643	$ 40,921

At December 31, 2006 the quoted market value of the holdings of publicly traded entities was approximately $50.0 million (December 31, 2005 – $61.3 million).

The Trust accounts for its interests in Taylor NGL Limited Partnership (Taylor) and Utility Group as equity investments.

In 2006 the Trust formed the Bear Mountain Wind Limited Partnership (BMWLP) with Aeolis Wind Power Corporation and the GreenWing Energy Development Limited Partnership (GEDLP) with GreenWing Energy Management Ltd. Through these partnerships, which are proportionately consolidated, the Trust invested $4.3 million (December 31, 2005 – $nil) in the development of wind power projects. Amortization of these deferred development costs will occur over a five-year period at the commencement of commercial operations.

In 2006 AltaGas provided advances to BMWLP, consisting of an initial funding advance of $0.2 million and a development fee loan of $0.5 million, secured against the assets of the Partnership, bearing interest at Canadian prime and repayable together with interest accrued thereon upon the receipt of financing proceeds.

On December 31, 2005 a private investment held by the Trust was written down by $0.6 million.

7. SHORT-TERM DEBT

At December 31, 2006 the Trust held a $50.0 million (December 31, 2005 – $50.0 million) unsecured demand revolving operating credit facility with a Canadian chartered bank. Draws on the facility bear interest at the lender's prime rate or at the bankers' acceptance rate plus a stamping fee. At December 31, 2006 the Trust had prime loans of $nil (December 31, 2005 – $2.7 million) and letters of credit of $3.0 million (December 31, 2005 – $6.9 million) outstanding against the facility.

Until September 31, 2005 the Trust held a $75.0 million unsecured 364-day extendible revolving-term letter of credit facility. Effective September 30, 2005 this facility was amended into a three-year extendible revolving letter of credit facility (see note 8 for a description of the amended facility).

The prime lending rate at December 31, 2006 was 6.0 percent (December 31, 2005 – 5.0 percent).

8. LONG-TERM DEBT

	2006	2005
Operating loans	**$ 154,306**	$ 154,064
Capital lease obligations	**11,181**	12,252
Medium-term notes	**100,000**	100,000
	265,487	266,316
Less current portion	**1,147**	1,071
	$ 264,340	$ 265,245

Letter of Credit Facility

At December 31, 2006 the Trust held a $75.0 million (December 31, 2005 – $75.0 million) unsecured three-year extendible revolving letter of credit facility with a Canadian chartered bank maturing on September 30, 2009. AltaGas may borrow up to $25.0 million by way of prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances on the letter of credit facility. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draw made. At December 31, 2006 the Trust had letters of credit of $63.3 million (December 31, 2005 – $37.3 million) outstanding against the extendible revolving-term letter of credit facility.

Operating Loans

At December 31, 2006 the Trust held a $300.0 million (December 31, 2005 – $300.0 million) unsecured extendible revolving three-year credit facility with a syndicate of Canadian chartered banks. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, LIBOR loans, bankers' acceptances or documentary credits. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draw. On September 30, 2006 AltaGas negotiated the extension of the maturity date of this facility to September 30, 2009.

At December 31, 2006 the Trust had drawn $154.3 million (December 31, 2005 – $154.1 million) against the facility. The prime lending rate at December 31, 2006 was 6.0 percent (December 31, 2005 – 5.0 percent). The average rate on the Trust's bankers' acceptances at December 31, 2006 was 5.0 percent (December 31, 2005 – 4.19 percent).

Medium-Term Notes

On April 29, 2005 AltaGas filed a Universal Shelf Prospectus pursuant to which the Trust may issue up to an aggregate of $500.0 million of Trust units and debt securities over a 25-month period. AltaGas filed a prospectus supplement on August 23, 2005 establishing AltaGas' medium-term note (MTN) program. On August 30, 2005 $100.0 million of 4.41 percent senior unsecured MTNs were issued. The notes mature on September 1, 2010, with interest payable semi-annually. The proceeds of the issue were used to repay bank debt.

Capital Lease Obligation

On September 1, 2004 the Trust entered into a 10-year capital lease with an option to extend the term for an additional 15 years. The lease has payment commitments over the next five years as follows:

2007	$ 1,878
2008	1,878
2009	1,878
2010	1,878
2011	1,878
Thereafter	5,014
	14,404
Less imputed interest at 6.85 percent	3,223
Present value of minimum lease payments	11,181
Less current portion	1,147
	$ 10,034

Interest expense on capital leases was $0.8 million in 2006 (December 31, 2005 – $0.9 million).

9. ASSET RETIREMENT OBLIGATIONS

	2006	2005
Balance, beginning of year	**$ 16,982**	$ 16,122
New obligations	**696**	366
Obligations settled	**(560)**	(183)
Obligations disposed	**–**	(649)
Revision in estimated cash flow	**4,802**	–
Accretion expense	**1,430**	1,326
Balance, end of year	**$ 23,350**	$ 16,982

AltaGas estimates the undiscounted cash required to settle the asset retirement obligations at December 31, 2006 was $57.0 million (December 31, 2005 – $48.1 million). The asset retirement obligations have been recorded in the financial statements at estimated values discounted at rates between 5.6 percent and 8.5 percent and are expected to be incurred between 2010 and 2040. The majority of the costs are expected to be incurred between 2025 and 2035. No assets have been legally restricted for settlement of the estimated liability.

10. INCOME TAXES

Taxation of the Trust

Payments received by the Trust in the form of interest, distributions or other income from its subsidiaries are taxable income to the Trust. The Trust is entitled to deduct, for income tax purposes, its costs and its distributions to unitholders. Since it distributes all of its income to unitholders, the Trust is not expected to be liable for income taxes currently.

On October 31, 2006 the Government of Canada announced a proposal to tax income distributed by flowthrough entities, beginning in 2011. Draft legislation to implement this tax was released for comment on December 21, 2006. Management will adapt the Trust's corporate organizational strategies as the tax legislation evolves, with the goal of growing unitholder value.

Taxation of the Operating Subsidiaries

Incorporated operating subsidiaries of the Trust are subject to tax in the same manner as any other corporation. Operating subsidiaries are generally not expected to pay significant taxes either currently or in the foreseeable future under existing tax legislation. Prior to the spin-out of the NGD segment, subsidiaries of the Trust that operated under utility board regulation incurred and expensed income tax on income earned.

Consolidated Tax Position

The tax provision recorded in the Consolidated Financial Statements differs from the amount computed by applying the combined Canadian federal and provincial income tax statutory rates to income before tax as follows:

	2006	2005
Income before taxes – consolidated	$ 113,382	$ 89,020
Income from AltaGas Income Trust distributed to unitholders	(92,385)	(86,099)
Income before income taxes – operating subsidiaries	20,997	2,921
Statutory income tax rate (%)	34.49	37.62
Expected taxes at statutory rates	7,242	1,099
Add (deduct) the tax effect of:		
Resource allowance	(1,048)	(2,204)
Large Corporations Tax	–	1,063
Rate reductions applied to future income tax liabilities	(7,822)	(440)
Permanent differences between accounting and tax bases of assets and liabilities	166	(445)
Other	333	(341)
Income tax provision (recovery)		
Current	7	2,096
Future	(1,136)	(3,364)
	$ (1,129)	$ (1,268)
Effective income tax rate (%)	(1.00)	(1.42)

AltaGas' income taxes are calculated according to government tax laws and regulations which result in different values for certain assets and liabilities for income tax purposes from values recorded for financial statement purposes. The amount shown on the Consolidated Balance Sheets as future income tax liabilities represents the net differences between tax values and book carrying values on the operating subsidiaries' balance sheets at substantially enacted tax rates. GAAP requires these future income tax liabilities to be recognized in the Consolidated Financial Statements. In the case of AltaGas, these future income taxes are not expected to result in cash taxes being paid due to the expectation of continued future intercompany interest deductions at the operating subsidiary level.

As at December 31, future income taxes were comprised of the following:

	2006	2005
Capital assets	$ 14,448	$ 20,577
Deferred debt charges	(26)	37
Unit issue costs	(1,209)	(2,074)
Partnerships	41,522	33,980
Deferred compensation	(3,408)	–
Other	(75)	(87)
	$ 51,252	$ 52,433

11. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

In the course of normal operations, the Trust issues short and long-term debt, and purchases and sells natural gas and power commodities. These activities result in exposures to fluctuations in interest rates and commodity prices. The Trust uses financial derivative instruments that result in cash settlements to manage the price or cash flow risk arising from these activities. The Trust does not make use of derivative instruments for speculative purposes.

The fair values of financial derivatives have been estimated using year-end market rates. These fair values approximate the amount that the Trust would receive or pay if the instruments were closed out at these dates.

Commodity Price Risk Management

Under the PPAs, AltaGas has an obligation to buy power at agreed terms and prices to December 31, 2020. The Trust sells the power to the Alberta Electric System Operator at spot prices and uses swaps and collars to fix the prices over time on a portion of the volumes. AltaGas' strategy is to lock in margins to provide predictable earnings. At December 31, 2006 the Trust had no intention to terminate any contracts prior to maturity.

At December 31, the Trust had the following contracts outstanding:

			Notional volume (MWh)			
Derivative Instruments	Fixed price (per MWh)	Period (months)	Sales	Purchases		Fair value
2006						
Swaps and collars	**$65.00 to $85.40**	**3 to 12**	**1,449,720**	**–**	**$**	**(14,452)**
Swaps and collars	**$52.50 to $69.50**	**3 to 132**	**–**	**519,264**	**$**	**6,092**
2005						
Swaps	$52.00 to $81.75	3 to 24	2,111,400	–	$	(23,936)
Swaps	$43.00 to $78.00	12 to 144	–	322,146	$	273

Foreign Exchange Risk Management

To manage foreign exchange risk, the Trust enters into foreign exchange forward contracts. The estimated fair value of the foreign exchange forward contracts at December 31, 2006 was $0.3 million (December 31, 2005 – $(6,000)).

Interest Rate Risk Management

To hedge against the effect of future interest rate movements, the Trust enters into interest rate swap agreements (swaps) to fix the interest rate on a portion of its bankers' acceptances issued under credit facilities.

In November 2005 AltaGas discontinued hedge accounting for $35.0 million in notional value swaps as a result of the maturity of the hedged bankers' acceptances. The swaps had an average remaining term of five to 10 months and a weighted average interest rate of 3.71 percent.

At December 31, the Trust had the following contracts outstanding:

Interest Rate Swaps	Period (months)	Principal	Weighted average interest rate	Fair value
2006	**1 to 27**	**$ 145,000**	**3.76%**	**$ 677**
2005	5 to 39	$ 185,000	3.75%	$ 921

Credit Risk on Financial Instruments

Credit risk results from the possibility that a counterparty to a derivative in which the Trust has an unrealized gain fails to perform according to the terms of the contract.

Credit exposure is minimized by entering into transactions with creditworthy counterparties in accordance with established credit policies and practices. At December 31, 2006 AltaGas did not have a significant concentration of credit risk with any single counterparty to financial instruments.

12. UNITHOLDERS' EQUITY

	2006	2005
Unitholders' capital *(note 13)*	**$ 463,750**	$ 417,114
Contributed surplus	**3,322**	2,839
Accumulated earnings	**401,618**	287,107
Accumulated dividends	**(41,114)**	(41,114)
Accumulated unitholders' distributions declared[(1)]	**(272,464)**	(161,664)
Distribution of common shares of Utility Group *(note 20)*	**(25,696)**	(25,696)
	$ 529,416	$ 478,586

[(1)] Accumulated cash distributions paid by the Trust as at December 31, 2006 were $262.9 million (as at December 31, 2005 – $152.9 million).

13. UNITHOLDERS' CAPITAL

The Trust is authorized to issue:

- An unlimited number of trust units redeemable for cash at the option of the holder;
- An unlimited number of AltaGas LP #1 Class B limited partnership units, which are exchangeable into trust units on a one-for-one basis. Prior to May 1, 2014 the exchange is at the option of the unitholder at any time, and at the option of the Trust should the number of AltaGas LP #1 units outstanding fall below 750,000. After May 1, 2014 the exchange is at the option of either the Trust or the unitholder; and
- An unlimited number of AltaGas LP #2 Class B limited partnership units, which are exchangeable into trust units on a one-for-one basis. Prior to May 1, 2009 the exchange is at the option of the unitholder at any time, and at the option of the Trust should the number of AltaGas LP #2 units outstanding fall below 1,000,000. After May 1, 2009 the exchange is at the option of either the Trust or the unitholder.

Trust Units Issued and Outstanding:	Number	Amount
December 31, 2004	49,825,241	$ 367,349
Units issued for cash on exercise of options	304,411	2,737
Units issued under DRIP[1]	1,147,640	27,739
Units issued for exchangeable units	1,228,222	7,029
December 31, 2005	52,505,514	404,854

Exchangeable Units Issued and Outstanding:		
December 31, 2004 issued by AltaGas LP #1	3,370,294	19,289
AltaGas LP #1 units redeemed for trust units	(1,228,222)	(7,029)
December 31, 2005	2,142,072	12,260
Issued and outstanding at December 31, 2005	54,647,586	417,114

Trust Units Issued and Outstanding:	Number	Amount
December 31, 2005	52,505,514	404,854
Units issued for cash on exercise of options	9,150	127
Units issued under DRIP[1]	1,745,630	46,509
Units issued for exchangeable units	53,258	305
December 31, 2006	**54,313,552**	**451,795**

Exchangeable Units Issued and Outstanding:		
December 31, 2005 issued by AltaGas LP #1	2,142,072	12,260
AltaGas LP #1 units redeemed for trust units	(53,258)	(305)
December 31, 2006	2,088,814	11,955
Issued and outstanding at December 31, 2006	**56,402,366**	**$ 463,750**

[1] Premium Distribution™, Distribution Reinvestment and Optional Unit Purchase Plan.

The Trust has a unit option plan under which employees and directors are eligible to receive grants. At December 31, 2006, 10 percent of units outstanding were reserved for issuance under the plan. To December 31, 2006 options granted under the plan generally had a term of 10 years to expiry and vested no longer than over a four-year period.

At December 31, 2006 outstanding options are exercisable at various dates to the year 2016 (December 31, 2005 – 2015). Options outstanding under the plan have a weighted average exercise price of $27.23 (December 31, 2005 – $9.40) and a weighted average remaining term of 9.23 years (December 31, 2005 – 9.25 years). As at December 31, 2006 the unexpensed fair value of unit option compensation cost associated with future periods was $0.9 million (December 31, 2005 – $0.3 million).

The following table summarizes information about the Trust's unit options:

	Options outstanding	
	Number of options	Weighted average exercise price
Unit options outstanding at December 31, 2005	359,200	$ 24.53
Granted	636,500	28.60
Exercised	(9,150)	13.93
Cancelled	(63,000)	27.53
Unit options outstanding at December 31, 2006	**923,550**	**$ 27.23**
Exercisable at December 31, 2006	**106,513**	**$ 20.48**

A summary of the plan at December 31, 2006:

	Options outstanding			Options exercisable	
	Number outstanding at December 31, 2006	Weighted average exercise price	Weighted average remaining contractual life (years)	Number exercisable at December 31, 2006	Weighted average exercise price
$5.00-$7.00	9,500	$ 6.15	3.43	9,500	$ 6.15
$7.01-$15.50	29,000	10.35	6.17	29,000	10.35
$15.51-$25.08	116,550	24.14	8.30	27,888	24.09
$25.09-$29.15	768,500	28.60	9.56	40,125	28.68
	923,550	**$ 27.23**	**9.23**	**106,513**	**$ 20.48**

The fair value of each option granted is estimated on the date of grant using the Black-Scholes option pricing model with weighted-average assumptions for grants as follows:

	2006	2005
Risk-free interest rate (%)	**4.36**	4.07
Expected life (years)	**10**	10
Expected volatility (%)	**20.89**	17.68
Annual distribution per unit ($)	**1.981**	1.85

Units Outstanding [1]	**2006**	2005
Weighted average number of units – basic	**55,468,969**	54,011,281
Effect of dilutive unit options	**47,216**	76,224
Weighted average number of units – diluted	**55,516,185**	54,087,505

(1) Includes exchangeable units.

In 2004 AltaGas implemented a unit-based compensation plan which awards phantom units to certain employees. The phantom units are valued on distributions declared and the trading price of the Trust's units. The units vest on a graded vesting schedule. The compensation expense recorded in 2006 in respect of this plan was $6.7 million (December 31, 2005 – $3.0 million). As at December 31, 2006 the unexpensed fair value of unit-based compensation costs associated with future periods was $9.9 million (December 31, 2005 – $7.5 million).

14. COMMITMENTS

Future minimum lease payments under operating leases for office space, office equipment, and automotive equipment are estimated as follows:

2007	$	3,180
2008		3,233
2009		3,041
2010		2,845
2011		2,643
	$	14,942

Under the terms of a 1997 long-term gas supply contract, the Trust is committed to supplying natural gas for prices ranging from $2.28/Mcf in 2006 to $2.40/Mcf by contract expiry in 2009. The Trust contracted with several producers to provide the volumes to fulfill this contract. In 1999, one of those producers defaulted on its obligation under its gas supply contract, resulting in the delivery commitment for 2,845 Mcf/d being assumed by the Trust. In 2006 the Trust entered into a contract with a supplier to provide these volumes at a fixed price. The fixed price contract expires in 2009.

In 1999 the Trust acquired a right to purchase natural gas from specific reserves for $0.05/Mcf for the life of the reserves. The production from these reserves was 1,321 Mcf/d in 2006 (2005 – 1,333 Mcf/d).

The Trust entered into an energy contract with the Alberta Balancing Pool Administrator for the right and obligation to purchase power from 100 MW of power capacity at the EPCOR Generation Inc.-operated Genesee power plant for a three-year term commencing April 1, 2003. The Trust had an obligation to pay a competitively priced fixed monthly capacity charge for the power capacity under this PPA. The contract expired March 31, 2006.

15. NET CHANGE IN NON-CASH WORKING CAPITAL

The net change in the following non-cash working capital items increased (decreased) cash flows from operations as follows:

		2006		2005
Accounts receivable	**$**	**(3,849)**	$	(60,177)
Inventory		**34**		155
Other current assets		**(4,856)**		424
Accounts payable and accrued liabilities		**(14,719)**		61,375
Customer deposits		**933**		(1,547)
Deferred revenue		**788**		–
Other current liabilities		**209**		(3,420)
		(21,460)		(3,190)
Less increase in working capital due to spin-out of Utility Group *(note 20)*		**–**		85
Less decrease (increase) in capital costs payable		**7,200**		(13,440)
Net change in non-cash working capital related to operations	**$**	**(14,260)**	$	(16,545)

The following cash payments have been included in the determination of earnings:

	2006	2005
Interest paid	**$ 13,521**	$ 17,829
Income taxes paid	**$ 62**	$ 1,321

16. PENSION PLANS AND RETIREE BENEFITS

Defined Contribution Plan

On July 1, 2005 AltaGas implemented a defined contribution (DC) pension plan for substantially all regular employees. The DC plan replaced the Group RRSP as AltaGas' primary employer-sponsored retirement arrangement.

The net pension expense recorded for the DC pension plan was $1.3 million for the year ended December 31, 2006 (six months ended December 31, 2005 – $0.6 million). The cost of the Group RRSP in 2005 prior to the implementation of the DC plan was $0.4 million.

Defined Benefit Plans

Effective August 25, 2004 the liability for a defined benefit, non-contributory pension plan in respect of nine Trust employees for pre-AltaGas pensionable service was assumed under Part II of the Salaried Employees' Pension Plan as a result of an acquisition. No future service accrues under this plan.

Effective January 1, 2005 the plan was amended in respect of certain employees who transferred employment from AltaGas Utilities Inc., a wholly owned subsidiary of the Trust during most of 2005. Assets and liabilities were transferred to Parts III and IV of the Salaried Employees' Pension Plan for three such employees during 2006.

On November 17, 2005 AltaGas indirectly disposed of its interest in AltaGas Utilities Inc. (AUI) through the spin-out of Utility Group. Substantially all of the employees of this subsidiary were members of one of two defined benefit non-contributory pension plans. An accrued benefit asset of $0.6 million, plan assets of $14.2 million, and an accrued benefit obligation of $16.1 million were transferred to Utility Group upon spin-out. The individual plans transferred to Utility Group had deficits on the Consolidated Balance Sheets of AltaGas. Part I of the Salaried Employees' Pension Plan had a deficit at the date of transfer of $1.5 million and the Bargaining Unit Pension Plan had a deficit of $0.3 million.

Effective with the spin-out of Utility Group on November 17, 2005 AltaGas has no obligations for retiree benefits other than pension and no current service costs in the registered defined benefit pension plan.

Plan contributions for Part I of the Salaried Employees' Pension Plan in 2005 were made in accordance with a 2002 report on the actuarial valuation for funding purposes. Plan contributions for Parts II, III and IV of the Salaried Employees' Pension Plan in 2006 were made in accordance with an actuarial valuation for funding purposes as at September 30, 2005 report dated March 29, 2006. At December 31, 2006 the accrued benefit obligation of the Trust for this plan was $1.9 million (December 31, 2005 – $1.7 million). At December 31, 2006, the plan had an accrued benefit liability of $0.3 million (December 31, 2005 – $0.3 million).

For the period ended December 31, 2006 the net pension expense was $(11,000) (December 31, 2005 – $0.8 million). The defined benefit plan expense in 2005 included expenses for the AUI plans up to November 17, 2005, the date of the spin-out of the NGD business.

Supplemental Executive Retirement Plan (SERP)

Effective July 1, 2005 the Trust instituted a non-registered, defined benefit retirement plan which provides defined pension benefits to eligible executives based on average earnings, years of service and age at retirement. At December 31, 2006 the accrued benefit obligation of the Trust for this plan was $2.1 million (December 31, 2005 – $1.3 million). At December 31, 2006, the plan had an accrued benefit liability of $1.0 million (December 31, 2005 – $0.1 million).

The SERP benefits will be paid from the general revenue of AltaGas as payments come due. Security will be provided for the SERP benefits through a letter of credit within a Retirement Compensation Arrangement Trust account.

For the period ended December 31, 2006, the net pension expense was $0.8 million (December 31, 2005 – $0.6 million).

The following table summarizes the details of the defined benefit plans:

	2006		2005
	Defined benefit pension plans	Defined benefit pension plans	Other benefit plans
Accrued benefit obligation			
Balance, beginning of year	**$ 2,987**	$ 13,670	$ 1,224
Net transfer in	**165**	1,583	–
Actuarial loss	**96**	1,551	352
Current service cost	**657**	1,058	50
Past service cost	**–**	971	–
Interest cost	**174**	880	67
Benefits paid	**–**	(579)	(18)
Accrued benefit obligation transferred to Utility Group	**–**	(16,147)	(1,675)
Balance, end of year	**4,079**	2,987	–
Plan assets			
Fair value, beginning of year	**1,409**	12,784	–
Net transfers in	**164**	1,262	–
Actual return on plan assets	**144**	904	–
Employer contributions	**12**	1,209	18
Benefits paid	**–**	(579)	(18)
Plan assets transferred to Utility Group	**–**	(14,171)	–
Fair value, end of year	**1,729**	1,409	–
Funded status	**(2,350)**	(1,578)	–
Unamortized transitional obligation	**–**	377	305
Unamortized past service costs	**855**	1,042	–
Unamortized net actuarial loss	**227**	2,287	685
Accrued benefit asset (liability)	**(1,268)**	2,128	990
Accrued benefit asset transferred to Utility Group	**–**	(2,585)	(990)
Accrued benefit liability	**$ (1,268)**	$ (457)	$ –

	2006	2005	
	Defined benefit pension plans	Defined benefit pension plans	Other benefit plans
Significant actuarial assumptions used as at December 31			
Discount rate (%)	**5.25 – 5.50**	5.25 – 5.50	6.00
Expected long-term rate of return on plan assets (%)	**6.00 – 6.75**	6.50	n/a
Rate of compensation increase (%)	**3.50 – 4.00**	3.50 – 4.00	5.00
Average remaining service life of active employees (years)	**9-12**	13-14	16
Net benefit plan expense for the year			
Current service cost and expenses	**$ 657**	$ 1,058	$ 50
Interest cost	**174**	880	67
Actual return on plan assets	**(144)**	(904)	–
Actuarial loss	**96**	1,551	352
Costs arising in the period	**783**	2,585	469
Differences between costs arising in the period and costs recognized in the period in respect of:			
Return on plan assets	**49**	72	–
Plan amendments	**–**	29	–
Actuarial gains	**(87)**	(1,299)	(340)
Past service costs	**77**	38	–
Transitional obligations	**–**	42	26
Net periodic benefit plan costs recognized	**$ 822**	$ 1,467	$ 155

17. RELATED PARTY TRANSACTIONS

In the normal course of business, the Trust and its affiliates transact with related parties. These transactions are recorded at their exchange amounts.

	2006	2005
Fees for administration, management and other services paid by:		
Utility Group to the Trust	**$ 30**	$ 4
The Trust to Utility Group	**$ 1,001**	$ 52
Natural gas sales by the Trust to Utility Group	**$ 84,046**	$ 25,842
Fees for operating services paid by Utility Group to the Trust	**$ 469**	$ 117
Transportation services provided by Utility Group to the Trust	**$ 560**	$ 98
Office space and furniture rental payments made by the Trust to a corporation owned by an employee	**$ 83**	$ 82

Included in accounts receivable at December 31, 2006 is $13.8 million (December 31, 2005 – $21.0 million) due to the Trust from related parties. Included in accounts payable at December 31, 2006 is $0.7 million (December 31, 2005 – $0.2 million) due from the Trust to related parties.

18. JOINT VENTURES

The Trust's proportionate interest in its joint venture arrangements is summarized as follows:

	2006	2005
Proportionate share of operating income		
Revenues	**$ 234,243**	$ 303,165
Expenses	**156,649**	245,054
	$ 77,594	$ 58,111
Proportionate share of net assets		
Current assets	**$ 44,386**	$ 27,022
Capital assets	**93,917**	46,821
Energy services arrangements, contracts and relationships	**81,292**	87,085
Long-term investments and other assets	**4,637**	–
Current liabilities	**(43,129)**	(28,928)
	$ 181,013	$ 132,000
Proportionate share of cash flows		
Operating activities	**$ 83,367**	$ 60,079
Investing activities	**(57,826)**	(3,799)
Financing activities	**(25,541)**	(56,280)
	$ –	$ –

19. GAIN ON INVESTMENT

The Trust's investment in Taylor is accounted for using the equity method. On February 7, 2005 the Trust sold 1.4 million limited partnership units of Taylor for proceeds of $12.8 million, realizing an after-tax gain of $4.1 million. The sale reduced the Trust's ownership in Taylor to 4.0 million units, or 14.0 percent.

On March 22, 2005 Taylor issued 13.0 million limited partnership units. AltaGas did not participate in this issue, which reduced the Trust's ownership in Taylor to 9.5 percent and resulted in an after-tax dilution gain of $3.8 million.

20. SPIN-OUT OF NATURAL GAS DISTRIBUTION BUSINESSES

On November 17, 2005 AltaGas completed the spin-out of its 100 percent-owned subsidiary Utility Group into a separate, publicly traded entity. Utility Group owns 100 percent of AUI, a one-third interest in Inuvik Gas Ltd. and a 24.9 percent interest in Heritage Gas Limited. Prior to the spin-out these entities comprised the NGD segment held by the Trust.

The spin-out of Utility Group was completed through a series of transactions. Holders of trust units of the Trust and holders of exchangeable partnership units of AltaGas LP #1 received one common share of Utility Group for every 13.9592 trust units or exchangeable units held on November 14, 2005. The number of common shares of Utility Group distributed to unitholders was 3,899,895 and reduced unitholders' equity by $25.7 million. The Trust sold 1,716,000 common shares of Utility Group at $7.50 per share for net proceeds of $10.7 million. Utility Group completed an initial public offering of 390,000 common shares at $7.50 per share for net proceeds of $2.7 million. This offering resulted in a 1.3 percent reduction of the Trust's interest in Utility Group to 26.7 percent. The series of transactions executed to effect the spin-out resulted in a net after-tax loss to the

Trust of $0.1 million. Concurrent with the spin-out, AltaGas settled amounts due from Utility Group and, together with the proceeds from the sale of Utility Group common shares, $85.4 million was used to repay the Trust's bank debt.

Prior to the completion of the spin-out, Utility Group's assets and operations were consolidated as the NGD segment. Subsequent to the spin-out, the Trust holds 2,184,010 common shares of the 8,189,905 Utility Group shares issued and outstanding. From November 17, 2005 the Trust accounted for its interest in Utility Group as a long-term investment in Utility Group using the equity method with no restatement of prior periods.

The financial statement impact of the series of transactions completed to execute the spin-out reduced assets, liabilities and accumulated earnings of the Trust as follows:

Net Impact of Spin-Out	
Current assets	$ (28,586)
Non-current assets	(129,749)
Current liabilities	29,870
Other liabilities	3,483
Distributions to unitholders	25,696
	$ (99,286)
Increase in long-term investments and other assets	$ 13,903
Repayment of intercompany advances to Utility Group	74,709
Net proceeds on sale of shares	10,674
	$ 99,286

21. SEGMENTED INFORMATION

AltaGas is an integrated energy trust with a portfolio of assets and services used to move energy from the source to the end-user. Transactions among the reporting segments are recorded at fair value. The Trust currently has five reportable segments. For the period from January 1, 2005 to November 16, 2005, the operating and financial results reflect the consolidated revenue and expenses of the entities that formed the Natural Gas Distribution segment, which was spun out on November 17, 2005. The following describes the reporting segments:

Field Gathering and Processing – natural gas gathering pipelines and processing facilities;

Extraction and Transmission – ethane and natural gas liquids extraction plants and natural gas and condensate transmission pipelines;

Power Generation – coal-fired and gas-fired power output under power purchase arrangements and other agreements;

Energy Services – energy management and gas services for natural gas and electricity, and oil and natural gas production; and

Corporate – the costs of providing corporate services and investments in public and private entities, corporate assets and general corporate overhead.

The following tables show the composition by segment:

For the year ended December 31, 2006	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Corporate	Intersegment elimination	Total
Revenue	**$ 139,016**	**$ 149,143**	**$ 199,344**	**$ 948,939**	**$ 4,415**	**$ (78,253)**	**$ 1,362,604**
Cost of sales	**(9,381)**	**(85,888)**	**(99,761)**	**(924,249)**	**–**	**75,588**	**(1,043,691)**
Operating and administrative	**(80,068)**	**(20,305)**	**(1,332)**	**(17,060)**	**(29,688)**	**2,665**	**(145,788)**
Amortization	**(23,579)**	**(7,733)**	**(7,382)**	**(4,848)**	**(2,319)**	**–**	**(45,861)**
Goodwill impairment	**(600)**	**–**	**–**	**–**	**–**	**–**	**(600)**
Operating income	**$ 25,388**	**$ 35,217**	**$ 90,869**	**$ 2,782**	**$ (27,592)**	**$ –**	**$ 126,664**
Net additions (reductions) to:							
Capital assets	**$ 62,295**	**$ 4,319**	**$ (28)**	**$ 1,652**	**$ 2,270**	**$ –**	**$ 70,508**
Energy services arrangements, contracts and relationships	**$ –**	**$ –**	**$ –**	**$ (36)**	**$ –**	**$ –**	**$ (36)**
Long-term investments and other assets	**$ –**	**$ –**	**$ 4,332**	**$ –**	**$ 1,390**	**$ –**	**$ 5,722**
Goodwill	**$ 215**	**$ 18,045**	**$ –**	**$ –**	**$ –**	**$ –**	**$ 18,260**
Segment assets	**$ 573,748**	**$ 143,004**	**$ 130,116**	**$ 219,205**	**$ 43,502**	**$ –**	**$ 1,109,575**

For the year ended December 31, 2005	Field Gathering and Processing	Extraction and Transmission	Power Generation	Energy Services	Natural Gas Distribution	Corporate	Intersegment elimination	Total
Revenue	$ 131,835	$ 181,314	$ 189,205	$ 1,080,225	$ 113,429	$ 10,915	$ (204,577)	$ 1,502,346
Cost of sales	(11,693)	(123,319)	(131,363)	(1,056,764)	(84,444)	–	202,102	(1,205,481)
Operating and administrative	(75,390)	(20,055)	(1,834)	(14,758)	(15,988)	(15,832)	2,475	(141,382)
Amortization	(20,660)	(7,558)	(7,313)	(3,151)	(6,755)	(1,935)	–	(47,372)
Operating income	$ 24,092	$ 30,382	$ 48,695	$ 5,552	$ 6,242	$ (6,852)	$ –	$ 108,111
Net additions (reductions) to:								
Capital assets	$ 46,320	$ 1,639	$ –	$ 1,384	$ (192,157)	$ 3,453	$ –	$ (139,361)
Energy services arrangements, contracts and relationships	$ –	$ –	$ –	$ 4,233	$ –	$ –	$ –	$ 4,233
Long-term investments and other assets	$ –	$ –	$ –	$ –	$ (2,327)	$ 8,372	$ –	$ 6,045
Goodwill	$ 815	$ 18,045	$ –	$ –	$ –	$ –	$ –	$ 18,860
Segment assets	$ 532,083	$ 211,150	$ 156,053	$ 120,140	$ –	$ 48,903	$ –	$ 1,068,329

22. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current financial statement presentation.

23. SUBSEQUENT EVENTS

On January 19, 2007 AltaGas issued $100 million of senior unsecured MTNs. The notes carry a coupon rate of 5.07 percent and mature on January 19, 2012. The net proceeds were used to pay down existing bank indebtedness and for general corporate purposes.

10-YEAR REVIEW **FINANCIAL AND OPERATING INFORMATION**

($ millions unless otherwise indicated)	**2006**	2005	2004	2003
FINANCIAL HIGHLIGHTS				
Income Statement				
Revenue	**1,362.6**	1,502.3	864.6	710.6
Net revenue(1)(2)				
Gathering, Processing and Energy Services	–	–	–	–
Gathering and Processing	–	–	160.1	137.8
Field Gathering and Processing	**129.7**	120.1	–	–
Extraction and Transmission	**63.2**	58.0	–	–
Power Generation	**99.6**	57.8	–	–
Energy Services	**24.7**	23.5	59.9	49.3
Natural Gas Distribution(3)	–	29.0	30.7	30.6
Corporate	**4.4**	10.9	–	–
Intersegment elimination	**(2.7)**	(2.4)	(0.3)	(0.4)
	318.9	296.9	250.4	217.3
EBITDA(1)	**173.1**	155.5	133.4	121.9
Net income	**114.5**	90.3	65.8	38.3
Net income per basic unit	**$ 2.06**	$ 1.67	$ 1.33	$ 0.84
EBITDA per basic unit(1)	**$ 3.12**	$ 2.88	$ 2.70	$ 2.68
Cash Flow				
Funds from operations(1)	**161.7**	129.0	108.6	90.2
Funds from operations per basic unit(1)	**$ 2.92**	$ 2.39	$ 2.20	$ 1.98
Distributions/dividends per unit declared(4)	**$ 1.995**	$ 1.85	$ 1.31	$ 0.38
Balance Sheet				
Capital assets	**677.9**	645.4	746.7	677.9
Energy services arrangements, contracts and relationships	**103.3**	110.9	113.1	101.0
Total assets	**1,109.6**	1,068.3	1,108.6	919.3
Short-term debt	–	2.7	7.0	4.5
Long-term debt	**265.5**	266.3	352.5	392.4
Unitholders' equity	**529.4**	478.6	483.5	363.3
Unit Data (millions)				
Units outstanding at year-end	**56.4**	54.6	53.2	45.7
Weighted average units outstanding for the year (basic)	**55.5**	54.0	49.4	45.5
Ratios (%)				
Return on average equity	**22.7**	18.4	15.7	10.9
Return on average invested capital	**16.3**	13.0	11.6	11.1
Debt as a percent of total capitalization	**33.4**	36.0	42.6	52.2
OPERATING RESULTS				
Field Gathering and Processing				
Capacity (gross Mmcf/d)(5)	**1,021**	962	913	861
Throughput (gross Mmcf/d)(6)	**549**	573	558	523
Throughput (gross annual Mmcf/d)	**555**	563	560	520
Capacity utilization (%)(6)	**54**	60	61	61
Extraction and Transmission				
Extraction inlet capacity (Mmcf/d)(5)	**554**	539	539	349
Production (Bbls/d)(7)	**19,696**	19,357	13,436	7,575
Transmission volumes (Mmcf/d)(8)(9)	**400**	432	432	403
Power Generation				
Volume of power sold (thousands of MWh)(7)	**2,878**	3,466	3,481	3,266
Price received on the sale of power ($/MWh)(7)	**69.26**	54.59	48.77	47.56
Alberta Power Pool price ($/MWh)(7)	**80.48**	70.19	54.54	62.98
Energy Services				
Energy management service contracts(5)	**1,394**	1,243	427	–
Average gas volumes marketed (GJ/d)	**327,057**	312,272	174,337	–
Natural Gas Distribution(3)(10)				
Volume of natural gas distributed				
Sales (Bcf)	–	10	14	14
Transportation (Bcf)	–	9	11	10
Number of customers(5)	–	61,447	60,430	59,543
Degree day variance (%)(11)	–	(1.4)	2.6	6.9

2002	2001	2000	1999	1998	1997
492.7	489.8	506.7	257.8	122.1	52.3
–	111.0	88.5	61.8	36.3	22.2
99.6	–	–	–	–	–
–	–	–	–	–	–
–	–	–	–	–	–
–	–	–	–	–	–
44.2	–	–	–	–	–
28.9	26.9	28.1	27.2	12.9	–
–	–	–	–	–	–
(2.8)	(2.9)	(0.3)	(3.1)	(1.4)	–
169.9	135.0	116.3	85.9	47.8	22.2
94.8	69.9	57.0	42.8	24.1	10.2
29.4	19.2	17.6	11.3	7.2	4.6
$ 0.70	$ 0.50	$ 0.46	$ 0.43	$ 0.39	$ 0.27
$ 2.24	$ 1.83	$ 1.50	$ 1.62	$ 1.31	$ 0.60
70.8	50.2	40.5	28.6	16.1	8.9
$ 1.67	$ 1.31	$ 1.06	$ 1.08	$ 0.88	$ 0.44
$ 0.28	$ 0.18	–	–	–	–
663.4	521.0	453.0	376.9	280.5	71.2
107.0	112.2	–	–	–	–
904.9	721.1	581.1	436.5	327.1	85.6
50.6	100.0	–	–	–	–
368.9	283.9	216.9	151.9	160.3	30.2
338.6	261.9	250.6	230.8	129.1	35.9
45.2	38.5	38.2	37.8	18.9	18.0
42.3	38.2	38.1	26.4	18.4	17.0
9.8	7.3	7.0	6.6	9.0	15.0
9.3	8.7	8.6	8.4	9.4	12.7
55.3	58.5	45.6	39.0	54.7	44.1
842	768	712	658	494	299
532	498	434	371	276	147
492	489	418	330	208	131
63	65	61	56	56	49
349	219	211	199	155	35
3,399	2,618	3,369	2,198	956	391
106	47	36	26	16	–
2,669	–	–	–	–	–
41.27	–	–	–	–	–
43.85	–	–	–	–	–
–	–	–	–	–	–
–	–	–	–	–	–
14	13	14	13	6	–
8	8	7	6	3	–
58,499	57,542	56,692	55,636	55,147	–
7.8	(3.4)	6.5	(1.1)	–	–

Comparative figures for 2004 and prior years have not been restated to conform to the current financial presentation.

(1) Non-GAAP financial measure. See discussion on page 22.

(2) Resegmentations occurred in 2005 and 2002. Prior years were not restated.

(3) AltaGas purchased 100 percent of the outstanding common shares of AltaGas Utilities Inc. on June 30, 1998. On November 17, 2005 AltaGas spun-out its Natural Gas Distribution segment to AltaGas Utility Group Inc., of which it retains a 26.7 percent interest.

(4) Distributions declared and paid do not include $0.54 per unit paid in November 2005 in the form of shares of AltaGas Utility Group Inc. as a result of the spin-out of the Natural Gas Distribution business.

(5) As at December 31.

(6) Fourth quarter average.

(7) Annual average.

(8) Average for fourth quarter except for 1998, which only included December.

(9) Volumes do not include condensate pipeline volumes.

(10) Excludes Inuvik Gas Ltd. and Heritage Gas Limited.

(11) Variance from 20-year average – positive variances are favourable.

energy to **GROW UNITHOLDER VALUE**

2006 DISTRIBUTIONS PER UNIT

Declaration Date	Record Date	Payment Date	Total Cash Distribution
January 13	January 25	February 15	$ 0.160
February 15	February 24	March 15	$ 0.160
March 1	March 27	April 17	$ 0.165
April 12	April 25	May 15	$ 0.165
May 10	May 25	June 15	$ 0.165
June 14	June 26	July 17	$ 0.165
July 13	July 25	August 15	$ 0.165
August 9	August 25	September 15	$ 0.170
September 13	September 25	October 16	$ 0.170
October 13	October 25	November 15	$ 0.170
November 8	November 27	December 15	$ 0.170
December 14	December 22	January 15	$ 0.170
Total 2006 Cash Distribution Declared			**$ 1.995**

PREMIUM DISTRIBUTION™, DISTRIBUTION REINVESTMENT AND OPTIONAL UNIT PURCHASE PLAN (DRIP OR THE PLAN)

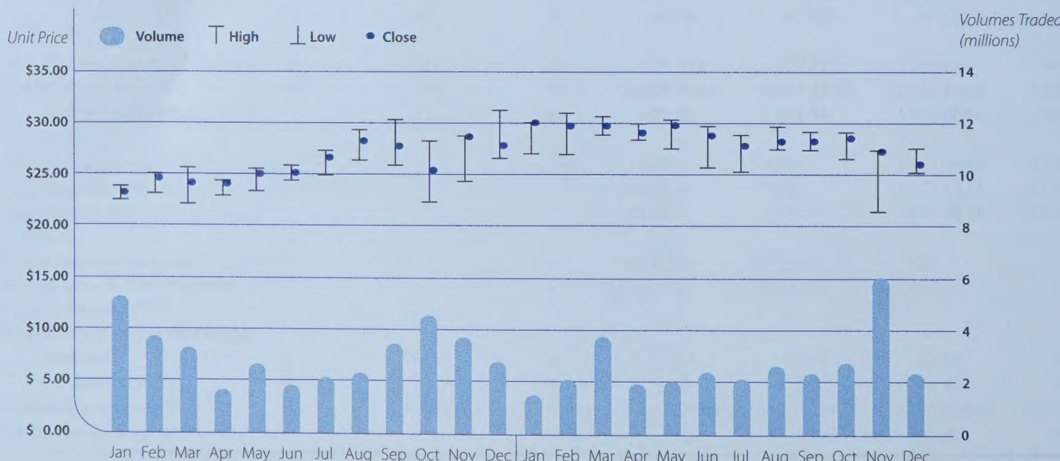
AltaGas Income Trust has adopted a Premium Distribution™, Distribution Reinvestment and Optional Unit Purchase Plan for holders of trust units of AltaGas Income Trust and holders of Class B Limited Partnership Units (Exchangeable Units) of either AltaGas Holding Limited Partnership No. 1 or AltaGas Holding Limited Partnership No. 2 (together, the AltaGas LPs).

The plan provides unitholders with a convenient and economical way to maximize their investment in AltaGas. The plan provides an alternative where eligible unitholders may elect, under the Premium Distribution™ component, to receive a premium cash distribution equal to 102 percent of the reinvested cash distribution or invested cash payment that such unitholders would have otherwise been entitled to receive on the distribution payment date. The plan also enables eligible unitholders to direct cash distributions paid by AltaGas in respect of their existing trust units be reinvested, or cash payments made by the AltaGas LPs in respect of their Exchangeable Units be invested, in additional trust units at 95 percent of the average market price (as defined in the plan) of a trust unit. Eligible unitholders can also make optional trust unit purchases at the weighted average market price subject to plan limits.

If you are eligible and wish to participate in the plan, eligible registered unitholders must enroll directly with Computershare Trust Company of Canada, while beneficial unitholders can contact their broker, investment dealer, financial institution or other nominee which holds the trust units or Exchangeable Units, as they must enroll on your behalf.

Complete details on DRIP are available on the AltaGas website at www.altagas.ca.

ALTAGAS UNIT PRICE AND VOLUME (ALA.UN)



High – $31.39 **Low** – $22.22 **Close** – $27.95

High – $31.17 **Low** – $21.55 **Close** – $26.20

CORPORATE **INFORMATION**

MANAGEMENT TEAM

David W. Cornhill
Chairman, President and Chief Executive Officer

Richard M. Alexander
Executive Vice President Chief Operating Officer and Chief Financial Officer

David R. Wright
Executive Vice President

Gregory A. Aarssen
Divisional Vice President Energy Management

Nancy A. Anderson
Vice President Business Development

Jeremy R. Baines
Treasurer

James B. Bracken
Senior Vice President Energy Services and Power

Dennis A. Dawson
Vice President General Counsel and Corporate Secretary

Massimiliano Fantuz
Vice President and President PremStar

Michael J. Kilby
Divisional Vice President Gas Services

Patricia M. Newson
Senior Vice President

Jeffrey F. Perry
Divisional Vice President Field Gathering and Processing

Marilyn A. Pfaefflin
Divisional Vice President Transmission

Deborah S. Stein
Vice President Finance

Kent E. Stout
Vice President Corporate Resources

Marshal L. Thompson
Senior Vice President External Relations and Corporate Risk

Randy W. Toone
Divisional Vice President Extraction and Transmission

AUDITORS

Ernst & Young LLP
Calgary, Alberta, Canada

TRANSFER AGENT

Computershare Trust
Company of Canada
Calgary, Alberta, Canada
Toll-free: 1-800-564-6253
Email: service@computershare.com

Investors are encouraged to contact Computershare for information concerning their security holdings.

STOCK EXCHANGE LISTING

Toronto Stock Exchange: ALA.UN

ANNUAL MEETING

The annual meeting will be held at 3:00 p.m. MDT on Thursday, April 26, 2007 at Bankers Hall Auditorium, Lower Level A/P3, 315 - 8th Avenue S.W., Calgary, Alberta.

INVESTOR RELATIONS

For investor relations enquiries, please contact:
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PHOTOGRAPHS

Front cover, left to right: Edmonton Ethane Extraction Plant; Warwick gas processing plant; AltaGas employees at work; TransAlta Corporation Sundance Power Plant; Iron Creek gas processing plant and Enercon wind turbine.

Page 6, top to bottom: Edmonton Ethane Extraction Plant; Energy Services customer Country Hills Toyota, Calgary, Alberta; AltaGas employee at work.

AltaGas

Well connected.

ALTAGAS INCOME TRUST

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